Air Pollution Emission Impacts Associated with Economic Market Potential of Distributed Generation in California

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Abstract

This study evaluates the net air emissions effects from the potential use of cost-effective distributed generation (DG) in California. The primary objectives of the study are, first, to estimate the economic market potential for distributed generation, and second, to determine the resulting air emissions given that level of deployment. The ultimate goal is to provide regulators and policymakers with information that will contribute to the development of strategies and policies regarding distributed generation.

Distributed generation may represent a less expensive energy delivery option, for utilities who desire to defer or avoid capital expenditures for generation, transmission and distribution infrastructure, for electric service providers (ESPs) and other market participants who may employ distributed generation to provide "value-added" services such as high reliability or premium power programs to customers, or for customers who may want to reduce overall energy costs, improve their electric service reliability, or increase their overall efficiency via cogeneration.

The analytical approach utilizes a three-step process. First, using the available distributed generation technologies and their costs, the economic market potential for distributed generation for both utilities and large commercial/industrial customers was estimated for the years 2002 and 2010. For utilities, both peaking and baseload applications were analyzed, and for customers the likely applications of cogeneration were included. These evaluations used economic models that compared the costs of the distributed generation technologies to the range of usual and customary costs of providing utility service. The percentage of new load for which distributed generation is more cost-effective than the utility approach represents the market potential.

Second, total air emissions were calculated for the years 2002 and 2010 given the estimated market penetration levels found for distributed generation, and compared to the central-generation-only scenario to estimate the net emissions from distributed generation. Finally, these results are integrated into an overall assessment of distributed generation economic market potential and total emissions impacts on a statewide basis, compared to the existing central generation mix. Emissions impacts are also estimated for specific individual air quality districts, including the San Francisco Bay Area, Sacramento Metro Area, San Joaquin Valley and South Coast air districts, among others.

Technologies included microturbines, the Advanced Turbine System (ATS), combustion turbines, Diesel engines, dual-fuel engines, Otto/spark engines, phosphoric acid fuel cells, and proton exchange membrane (PEM) fuel cells. Renewables such as wind, solar and biomass were not considered because of their high costs and limited dispatchability, factors that essentially inhibit significant market penetration. Air emissions of interest included NO_x, SO_2, CO, CO_2, volatile organic compounds (VOC) and particulates.

Executive Summary

Project Objectives

The scope of this study is an evaluation of the net air emissions effects that would result from use of cost-effective distributed generation (DG) in California. Distributed generation would be used by utilities and customers in lieu of the conventional means of producing, transporting, and delivering electricity. Distributed generation is not currently a mainstream approach for customers or utilities; this study was undertaken in the spirit of anticipating the possible air emissions implications prior to significant major market penetration.

The primary objectives are to provide an estimate of economic market potential for distributed generation in California, and to estimate the resulting in-state air emissions given that level of deployment. The ultimate goal is to provide the California Air Resources Board with insights into these concepts, to assist in the development of regulatory strategies and policies regarding distributed generation.

Oversight and direction for the project was provided by a Project Advisory Board consisting of representatives of the California Air Resources Board, the California Energy Commission, the Bay Area Air Quality Management District, utilities, manufacturers and other stakeholders. The Board reviewed the scope, objectives, assumptions and the selection of distributed generation technologies to be used for the study, monitored the progress of the work, provided input and direction, and reviewed the final report.

Key Study Assumptions

- Distributed generation utility perspective market potential is evaluated for new load (load growth) applications only.
- Emissions from distributed generation are netted against existing in-state generation resources only; out of state generation is beyond the purview of CARB.
- Distributed generation technology availability, cost and performance specifications are based on manufacturers' data, review by the Project Advisory Board, and input from CARB staff.
- Natural gas cost and availability are based on current data.
- Market-based values are used for generation capacity and energy, i.e., the values the utility would pay to the generation market.
- Electric utilities are allowed to own and operate distributed generation, they have confidence in the performance and reliability of distributed generation, and they know where and how to deploy it to obtain system benefits.
- Customers' sources for capital are higher cost than utilities' sources, and they must pay utility rates for their purchased power. Exit fees and standby charges are not considered, and interconnection fees are assumed to be minimal. Only large customer loads, primarily industrial, were considered "at risk."
- No sharing of the benefits of distributed generation between customers and utilities.

Analysis Approach Overview

Estimating the potential amount of air emissions from utility-owned distributed generation in California requires a three-step process:

1) estimate economic market potential for distributed generation options considered, that indicates the number and/or nameplate capacity of distributed generators that might be installed, given purely financial criteria:

   Electric utility perspective – comparing the cost to the utility to own and operate a distributed generator to the avoided cost for the conventional grid-only option. Avoided costs are calculated using market-based generation costs and avoided transmission and distribution costs. Distributed generation is assumed to address load <u>growth</u> only.

   Electric utility **customer perspective**
   customer to own and operate a distributed generator to the price for utility electricity that the customer would otherwise purchase.

   calculate total air emissions for the central-only generation scenario versus a

   generator is achieved; then

3) integrate results from steps one and two into an overall assessment of distributed generation economic market potential on a statewide basis, including total

   existing mix of in-state generation which is dominated by facilities with limited or no air emissions, mostly nuclear and hydroelectric. The comparison of distributed

   of the existing system.

For this analysis, electric utility customers are restricted to larger industrial/institutional

generation projects, internalize benefits associated with distributed generators and to plan, finance, and seek approval for distributed generation projects.

results between those years include: distributed generator efficiency is likely to improve, prices for less mature distributed generators are likely to drop, and the amount of load

Economic Market Potential Estimation Results Overview

Utility Perspective Economic Market Potential

Utility Peak Load Distributed Generators

As shown in Table 10, in 2002 even the least attractive distributed generation option

for
turbines are cost-effective for about 37% and 32% of load growth respectively.

Spark-gas engine gensets and the Advanced Turbine System (ATS) are more cost-effective than the grid in about 54% and 58% of cases, respectively. Diesel engines are the most cost-effective: they have competitive cost in about 75% of situations.

In 2010 load growth is 1,144 MW. As shown in Table 11, economic market potential increases considerably for most distributed generators: dual fueled engines are now cost-effective for 52% of new load, conventional combustion turbines increase to 79%, ATSs improve to 70%, and microturbines increase to 75%. Spark-gas and Diesel engines hold steady at about 54% and 75%, respectively.

To determine the economic market potential in MW, the percentage values described above are multiplied by the load growth for the year being considered. For example, in 2002 load growth is 976 MW. ATSs are cost-effective for 58% of that, 567 MW.

Utility Baseload Distributed Generators

For 2002 (results are shown in Table 12) the ATS is the most attractive baseload distributed generator option: it is less expensive than the utility grid option for about 33% of load growth (376 MW of total load growth of 976 MW). Small conventional combustion turbines could address 10% of new load cost-effectively while microturbines might be cost-effective for about 4% of new load. Fuel cells and dual fuel engines are not cost-effective.

As shown in Table 13, for load growth of 1,144 MW in 2010, the ATS is still the most attractive baseload distributed generation option, as it is economically competitive for 42% of load growth. Combustion turbines meet about 16% of new load cost-effectively. Microturbines are less expensive than the utility grid option for 14% of new load. Natural gas fueled proton-exchange membrane (PEM) fuel cells are economically competitive for about 2% of load added. Phosphoric acid fuel cells and dual fuel engines are not cost-effective for any new load.

Percentage values given above are multiplied by the load growth for the year being considered to estimate the economic market potential in MW. In 2002 load growth is 976 MW and ATSs are cost-effective for 33% of that, 322 MW.

Customer Perspective Economic Market Potential

For most areas of the state, distributed generators are not cost-effective for customer bill reduction. For expected electric utility prices that apply to least 80% of the state, the best total benefit/cost (B/C) values were only about 0.9, which is not cost-effective. Moreover, to achieve even that high a B/C ratio required operation in combined heat and power (CHP, or cogeneration) mode. Furthermore, only those distributed generators with CHP had net incremental cost that was low enough to justify more than a few hundred hours of operation. Total B/C for engines, operated mostly for peak-load reduction, were somewhat lower than those for CHP distributed generators, at about .65. Fuel cells are not cost-effective unless relatively high electric prices prevail, and/or expected fuel efficiency and installed cost targets are achieved.

For regions of the state where higher electricity prices prevail, distributed generators may be cost-effective for operation during several thousand hours per year. For example, both the relatively inefficient microturbine and the expensive to operate Diesel engine are cost-effective to operate for more than 3,400 hours per year in areas with high energy prices.

Key Conclusions

Economic Market Potential for Utility Peaking Distributed Generators

Economic market potential (MW) for utility-owned peaking distributed generators is substantial: they can provide peaking capacity at lower overall cost than the traditional central generation and wires solution in many cases. But, as noted above, cost-effective peaking distributed generators would contribute a very small part of the energy needed to serve new load, because utility peaking distributed generators only have to run for few hours per year to provide the capacity needed to "clip" localized electric peak loads.

Economic Market Potential for Utility Baseload Distributed Generators

Overall, baseload distributed generators have a difficult time competing with the wholesale market (the grid) for electricity that provides lower cost electric energy than most baseload distributed generators can generate. The economic market potential for distributed generators for utility base load applications is likely to be low for the next few years, but should increase slowly over time as the cost and performance of distributed generation technologies improves.

There is one key exception: CHP, where it can be used, increases the economic viability of distributed generation projects. Results indicate that CHP does indeed increase economic market potential for combustion turbine based distributed generators. CHP also has an important impact on net air emissions from a given distributed generator (relative to generation-only distributed generation projects).

Economic Market Potential for Customer Distributed Generators

Electric utility customers will tend to use distributed generators primarily to avoid peak demand charges, and also to avoid high electric energy prices during on-peak price periods. Only if a distributed generator is very fuel-efficient, or if CHP is employed, will utility customer–owned distributed generators be economic for serving all the customer's electricity needs for the entire year (i.e., few distributed generators can compete with the grid for off-peak electric energy).

Natural gas and Diesel engines are the most attractive option for customer peak shaving, due to competitive equipment cost and fuel efficiency. Combustion turbine based options are somewhat less attractive for peak shaving.

It should be noted that including the effects of standby charges or exit fees in the customer financial evaluation was beyond the scope of this analysis.

Air Emissions from Peaking Distributed Generators

Cost-effective utility peaking distributed generators will have higher emissions *per unit of energy* produced, compared to the existing mix of in-state generation. This is especially true for Diesel engines; if Diesels capture 75.5% of the 976 MW of new load in 2002, then total NO_x emissions in 2002 will be 1,256 tons, vs. only 13 tons for central generation only (Table 10). Other emissions for Diesels are higher, though not to the same degree; and other technologies have lesser impacts to varying degrees. In contrast, spark gas engines can serve 54% of the load growth, resulting in total NO_x emissions of 175 tons. Other technologies cannot economically serve as much of the new load as Diesel engines can, but they contribute much lower emissions. For example, the microturbine is cost-effective for about 29% of load growth while total NO_x emissions would be 44 tons (compared to the central generation only figure of 13 tons).

Moreover, there may be a high correlation between peaking distributed generator operation and peak ozone occurrences. Readers should note that it is outside of the scope of this analysis to consider time-specific emissions effects; however, all emissions attributable to peak power production would occur in a short timeframe. Ozone standards are based on 1-hour and 8-hour averages; any increase in emissions in that timeframe may have an impact on air quality.

For customers, the "make or buy" decision is based on different criteria, primarily electricity price, than for utilities whose criterion of merit is location-specific avoided cost. Customers operate distributed generation to reduce their overall energy bill, whereas utilities use distributed generation to reduce overall cost.

The number of hours during which a utility experiences peak demand (either locally or system-wide) is usually less than 200 hours. But 600 hours per year is a typical number of annual hours during which utility peak demand charges and high on-peak energy prices apply for customers, usually during weekday afternoons in summer. Because customers would have to run distributed generators during all of those 600 on-peak hours to accomplish "peak shaving," total air emissions from customer-owned distributed generators will be about 3 times higher than the emissions from utility peaking distributed generators only running 200 hours per year.

It can actually be even more complicated: It may be that a customer distributed generator is cost-effective for several thousand hours of operation per year whereas the utility may optimize the benefits of its distributed generation by operating it for very few hours per year.

Air Emissions from Baseload Distributed Generators

In general, utility-owned baseload distributed generators will have a difficult time competing with very low grid energy prices, so their economic market potential will be limited and their emissions will increase only slightly from the few baseload distributed generators that are economically viable.

avoid electricity prices and

for baseload operation. Furthermore, when crediting distributed generation for "avoided" boiler emissions, the __ emissions from CHP distributed generators (generator emissions less avoided boiler emissions) will be lower than the gross emissions from generation-

As with peaking distributed generators, the customer's decision about whether to use baseload distributed generation in lieu of grid power is based on price, not location-

their overall bill cost). So, often the number of

utility. For example, in the evaluation some distributed generators would run enough to meet all of a given customer's electric energy needs, whereas the utility would only run

needs of customers.

Cost-effective Distributed Generators Compared to the "Next" Central Generation Plant

This study compared the emissions from potentially cost-effective distributed generation to the existing in-state California generation mix, not the emissions from a to-be-determined new power plant. The current in-state central generation mix is so clean that virtually no distributed generation source could lower net emissions, even including line losses. Estimating the projected emissions from the unknown future mix of in-state generating plants was beyond the scope of this study, but the trend is for California's retrofit rules to further reduce power plant emissions, and for new generation to be cleaner than existing facilities.

Next Steps and R&D Needs

Since the original intent of this effort was to examine distributed generation emissions "from 30,000 feet", and because the distributed generation technologies and market factors are evolving rapidly, many aspects of this analysis seem worthy of further study or refinement.

Perhaps the most important next step might be to broaden the customer segments to include commercial or even residential sectors, since the price paid for electricity directly determines the customer market penetration. Also, distributed generation technologies continue to advance and expand their market applications. More real-world market factors may now be ready for inclusion or refinement, such as exit fees, standby charges or interconnection costs for customer owned distributed generation; similarly the real availability of natural gas to candidate sites, costs for gas connection, and firmness of service may warrant further analysis. Another emerging market niche is the activation of standby generators especially for temporary service to help utilities get through summer peaks. All of these issues might merit further in-depth examination.

1. Introduction

Project Scope and Goal

The scope of this study is an evaluation of the net air emissions effects that would result from use of cost-effective distributed generation (DG) in California. Distributed generation would be used by utilities and customers in lieu of the conventional means of producing, transporting, and delivering electricity. Distributed generation is not currently a mainstream approach for customers or utilities; this study was undertaken in the spirit of anticipating the possible air emissions implications prior to significant major market penetration.

The primary objectives are to provide an estimate of economic market potential for distributed generation in California, and to estimate the resulting in-state air emissions given that level of deployment. The ultimate goal is to provide the California Air Resources Board with insights into these concepts, to assist in the development of regulatory strategies and policies regarding distributed generation.

The distributed generators investigated range in generation capacity from 50 kW (kiloWatts) to 5 MW (MegaWatts). They would be used on-site by customers for "self generation," or by electric utilities, connected to the utility power distribution system, at a customer's site, on a distribution feeder or a substation.

The Distributed Utility Concept Overview

The Distributed Utility (DU) concept involves use of modular distributed electric energy generation or storage or geographically targeted demand side management; these technologies are collectively referred to as "distributed resources" (DRs). Distributed resources provide the capacity to supply electric energy when and where needed, within an electric utility's distribution system or at energy end-users' facilities. A comprehensive treatise of the Distributed Utility concept can be found in the Distributed Utility Valuation (DUV) Project Monograph, published by EPRI and NREL [1].

Electric utility interest in distributed resources is growing. Distributed resources may serve as a less expensive option when compared to the traditional utility alternatives: upgrades or additions to central station generation or to transmission and distribution infrastructure. For example, electric utilities can use distributed resources to delay, reduce or eliminate the need for additional generation, transmission and distribution infrastructure (the "wires" solution). In any given circumstance those costs may include some or all of the following:

- central electricity generation variable costs: fuel, operations and maintenance costs
- central electricity generation new/upgrade plant/equipment cost
- electricity transmission new/upgrade plant/equipment cost
- electricity distribution new/upgrade plant/equipment cost

A utility could also use distributed resources to provide "value-added" services such as high reliability or premium power programs to specific areas within its service area or to specific customers.

New players in the deregulated electric utility industry, such as electric service providers (ESPs), may employ distributed resources as competitive offerings for customers.

Electric utility customers may install distributed resources to reduce overall energy costs ("bill management"), or to provide elements of electric service not available from the utility, such as high electric service reliability, high quality power or heat for industrial processes.

Given those premises and emerging trends in the electricity marketplace, there are strong indications that utilities, their customers and their competitors (e.g., ESPs) may use distributed generation to reduce costs and/or to expand services. If so, there are potential implications for total air emissions. The goal of this study is to give the Air Resources Board a better understanding of the potential for economic deployment of distributed generators and what the resulting changes in total air emissions in California might be.

Analytical Methodology

Estimating the potential amount of air emissions from distributed generation in California requires a three step analytical process. First, the economic market potential for distributed generation is estimated, given the available technologies and their costs, for both utility and large commercial/industrial customers. Economic models are used to compare the costs of the distributed generation technologies to the range of usual and customary costs of providing utility service. The percentage of new load for which distributed generation is more cost-effective than the utility approach represents the market potential. Technologies evaluated included microturbines, the Advanced Turbine System (ATS), combustion turbines, Diesel engines, dual-fuel engines, Otto/spark engines, phosphoric acid fuel cells, and proton exchange membrane (PEM) fuel cells.

Second, the total air emissions impacts for the years 2002 and 2010 are estimated given the market penetration levels found for distributed generation, and are compared to the emissions from the central-generation-only scenario, in order to estimate the net emissions from distributed generation. (Only the mix of generation within the state of California is considered; comparing the air impacts of distributed generation in California to the impacts associated with generating plants that may import energy into California is outside the scope of this analysis.)

Finally, the results from steps one and two are integrated into an overall assessment of distributed generation economic market potential on a statewide basis, including the resulting total emissions impacts. Impacts are also evaluated for specific regional air districts of interest.

2. Analytical Approach

Economic Market Potential Estimation

The goal of this project is to estimate the air emissions impacts resulting from the market penetration of distributed generation in California. That requires a two step process. The first step entails estimation of the market potential for *economically viable* distributed generation capacity (i.e., economic market potential). (Units of economic market potential are MW/year.) That indicates the amount of distributed generation, in units of MW, that would be deployed given purely economic considerations. The estimate is based on a comparison of annualized **cost** to own and operate a distributed generator with the range[1] of possible annualized monetary **benefit** from the technology.

For electric utilities, benefits associated with distributed generation are referred to as the "avoided cost," i.e., the cost that the utility would incur if the distributed generation is not used. The DUVal methodology (proprietary to Distributed Utility Associates) was used to make the estimate (please see details in the paper Introduction to DUVal Methodology [2]). While the authors assumed that generation, transmission and distribution are separately owned, it was also assumed that there will exist an open market for the benefits created by distributed generation owned by any market participant.

In a similar manner, the DUVal-C model is used to estimate the economic market potential for distributed generation for large institutional/industrial electricity users, as described in detail in Section 6: Customer Evaluation and Bill Analysis.

Emissions Implications of Economic Market Potential

After estimating economic market potential for distributed generators, total air emissions from the cost-effective distributed generators are calculated (based on cost-effective hours of operation and number of MW). To determine emission impacts, each distributed generator's air emissions are compared to those that would have resulted from central generation only. This requires a comparison of total air emissions without adoption of distributed generation to the total air emissions with adoption of distributed generation.

If distributed generation is not economically sound, and thus is not used, all electricity is assumed to be supplied by central generation plants which emit the assumed amounts of the six pollutants per kWh produced, as shown in Section 4: Utility Central Station Generation Fuels, Cost and Air Emissions. Air emissions of interest include NO_x, SO_x, CO, CO_2, volatile organic compounds (VOCs) and particulate matter (PM).

If distributed generators are cost-effective, and thus supply some or all of that same electricity, then the overall emissions profile would be different, reflecting an economically efficient mix of central and distributed generation. Air impacts (total

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[1] The cost to serve customers varies from location to location. DUVal captures this very important phenomenon as described in Section 5: Utility Avoided Cost Evaluation.

change due to adoption of distributed generation) can then be calculated as the difference between emissions given the central-generation-only scenario and total emissions from the central-and-economic distributed generation scenario.

Operation of distributed generators in CHP mode also has air emissions implications. Heat from CHP is used for processes such as hot water heating, building heat, low pressure process steam, etc. Normally that heat would be produced by burning fuel in a boiler. Avoided boiler operation results in reduced air emissions. Please See Appendix D about CHP for details.

Note that, for this study, distributed generators were assumed to compete against the "average" power plant, i.e., a composite power plant reflecting the mix of all generator types and fuels used for central power generation statewide. As with economic market potential estimates, it could be argued that distributed generators would compete against new central generation plants, those that would have to be built in the absence of distributed generation. Newer generation plants (primarily combustion turbine based) tend to be cleaner, more efficient, and may or may not have lower cost-of-production relative to existing power plants.

Distributed Generators Evaluated

For this study only distributed generation devices were considered. Distributed resources not addressed by this study are: a) non-generation distributed resource options include geographically targeted demand side management (DSM) and energy storage and b) non-dispatchable distributed generation options including wind turbines and photovoltaics.

Technologies chosen were either:

- considered by the project advisors and authors to be commercially viable, reliable and serviceable, currently or within the next two years; or
- "emerging" options that have great promise as clean electricity sources.

There are literally hundreds of distributed generator systems that could be evaluated. Most of them will be distributed generators that convert liquid or gaseous fuel (usually Diesel fuel or natural gas) into electricity. The most common types of distributed generators are combustion turbines, internal combustion piston-driven engines and fuel cells.

Renewable technologies such as photovoltaics and wind were not included in the study, due to their non-dispatchability and zero emissions.

All baseload distributed generators evaluated for this study are assumed to be capable of providing thermal energy via CHP, irrespective of the economic merit of so doing.

The distributed generation technologies evaluated in this study are described in greater detail in Section 3. Distributed Generation Cost, Performance, and Air Emissions, and in Appendix C. Description of Distributed Generators.

3. Distributed Generation Cost, Performance, and Air Emissions

For the utility portion of the evaluation, a total of six peaking and six baseload distributed generators were evaluated. Cost, performance and emissions for each (not including CHP) are shown in Tables 2 through 5.

These data were compiled from a variety of sources. Data for Diesel engines and spark/gas engines were supplied by Caterpillar, Inc. [3] and by the California Air Resources Board (CARB) [4]; see Appendix F for details. Extensive discussions among the authors, these parties and the project advisors resulted in the data used in this report. As the discussion in the Appendix notes, emissions from these types of engines can vary over considerable ranges, due to age, size, manufacturer and emissions technologies installed. The data used in this report resulted from the best estimates of engine performance based on application, size, and expected air regulations.

Data for the Advanced Turbine System (ATS) was supplied by Solar Turbines Corp. [5]. Phosphoric acid fuel cell data were obtained from the NYSERDA report, 200 kW Fuel Cell Monitoring and Evaluation Program Final Report [6] and from ONSI Corporation [7], a leading fuel cell developer. Since proton exchange membrane (PEM) fuel cells are still in the research stage, data for PEM fuel cells used in this report were compiled by assimilating and reconciling data available from leading developer Ballard Corporation [8], MC Power Corp. [9], and Joan Ogden of Princeton University. Microturbine data are a composite of data supplied by Allied Signal Power Systems (now Honeywell Power Systems) [10] and Capstone Turbines [11], who are the leading microturbine developers and advisors to this project.

Notes on the distributed generation data:

1. Emissions data used for internal combustion engines in 2010 reflect limits that will be imposed in future years, and may not be attainable with current technology.
2. Costs used throughout this report are in constant 1999 dollars.
3. Costs for acquisition of air permits are not included in the analysis; these costs are highly variable and case-specific.
4. Installed costs for actual distributed generation projects are certain to be site-specific, and manufacturers' targets for cost and performance may be optimistic.
5. PEM fuel cells will have trace amounts of NO_x emissions due to the process used for reforming the natural gas fuel.

Distributed Generation Technology Cost and Performance

There are many types of technically viable distributed generation systems that could be evaluated. Most convert liquid or gaseous fuel (usually Diesel fuel or natural gas) into electricity. Most common of those are combustion turbines, internal combustion piston-driven engines, and fuel cells. For the customer-perspective bill analysis evaluation, a subset of the distributed generators listed in Tables 2 – 5 was used.

Distributed Generation Combined Heat and Power Operation

Most types of distributed generation, and all options considered for this study, can provide useful and valuable thermal energy by capturing otherwise wasted heat produced during electricity generation, and using the heat to heat water, air, or for process heat. This process is called combined heat and power (CHP).

For energy users requiring substantial amounts of heat, especially industrial, institutional and agricultural operations, CHP can improve the economics of specific distributed generation projects significantly and it can reduce a facility's overall cost of energy considerably.

It was assumed that combustion of fuel to produce heat (usually in a boiler) is typically about 85% efficient. Therefore, each Btu of heat captured from the distributed generator in a CHP process offsets the need to burn about 1.18 Btu of fuel.

For the utility avoided cost evaluation, it is estimated that 15% of new load *could* use CHP. (Note that CHP applies only to generators operated in baseload mode.) For the customer bill analysis two distributed generators were evaluated as CHP generators: the microturbine and the ATS. Cost, performance and emissions data for distributed generators in CHP mode were developed from manufacturers' data and are representative averages based on the range of typical CHP applications. The incremental cost for CHP is assumed to be $230/kW, representing the typical costs for piping, heat exchangers and engineering associated with CHP.

CHP can also yield substantial environmental benefits due to the avoided emissions from boilers. Recouping waste heat from the distributed generator for customer loads (e.g., space or water heating, industrial processes, etc.) can replace the heat produced by burning fuel in a boiler; if the boiler can be replaced by CHP then its emissions are avoided. Nominal values for avoidable boiler air emissions are shown in Table 1; they are based on the leading data source for such information, the U. S. Environmental Protection Agency [12]. (These values are representative of the existing population of boilers which would be the logical candidates for replacement by CHP, and as such are somewhat higher than would be the case for new, more efficient boilers.) Avoided

Table 1. Avoided Boiler Air Emissions for CHP Operation, lb/$MMBtu_{in}$

	NO_x	SO_x	CO	CO	VOC	PM
Nominal	.14706	.00059	.0824	118	.00539	.00745
Best Reported	.03137		.0235			
Poorest Reported	.2745		.0961			
California	.09804	.00059	.0824	118	.00539	.00745

emissions for each kilowatt-hour of electric generation from CHP are calculated as follows:

$$(((\text{DG Heat Rate} - 3{,}413\ \text{Btu/kWh}) * \text{Waste Heat Recovery Factor}) \div \text{Boiler Efficiency}) * (\text{Pounds of Emissions per Btu of fuel in})$$

California has more stringent requirements for NO_x emissions than the nation as a whole; for this reason, the avoided NO_x emissions used in this report are 0.09804 lb/MMBtu (please refer to Appendix D for details).

Fuel for Distributed Generators

In this report, the following assumptions apply to the fuels used in the various types of distributed generators:

- microturbine, combustion turbine, Advanced Turbine System (ATS), and spark gas engines all use natural gas fuel
- dual fueled engines run on a combination of natural gas and a small fraction of Diesel fuel
- Diesel engines require Diesel fuel (at a cost of $4.24/MMBtu)
- fuel cells use natural gas (used with a reformer to generate hydrogen)

In this report, it is assumed that large volume purchases of natural gas will result in a price break compared to small volume gas purchases:

- Natural gas at utility <u>substation</u> locations and for large industrial/institutional electric utility customers is assumed to be high volume purchases; the city gate price of $3/MMBtu is assumed.
- Natural gas for distributed generators located at or near customer loads (i.e., <u>feeder</u> locations) assumes smaller purchase volumes and thus higher commodity and delivery charges; retail price assumed is $5.60/MMBtu.
- Natural gas for large industrial/institutional customer-owned distributed generators was assumed to be $3.3/MMBtu.

Distributed Generation Assumptions and Caveats

Emissions control technology continues to advance. As a result, many new distributed generators are among the cleanest generating sources available, and continue to improve. New central station generation also benefits from this technology, and existing plants can be retrofitted to improve their performance as well. Therefore, determining the exact emissions numbers to use for a given generating technology is somewhat akin to hitting a moving target. Key factors to consider when deciding which numbers to use are: what is technically feasible, what is cost-effective, and what area- or region-specific emissions regulations apply in a given case.

Table 2. Peaking Distributed Generation Technologies' Cost, Performance and Emissions, 2002

Distributed Generator Type	Power (kW)	Installed Cost		Heat Rate	Variable O&M	Emissions lb/kWh					
		$/kW	$/kW-yr*	Btu/kWh	$/kWh	NO_x	SO_x	CO	CO_2	VOC	PM
Microturbine	45	475	54.6	12,500	.014	.00125	.00003	.00285	1.25	.000045	.000091
ATS	4200	450	51.8	9,500	.01	.000211	.000021	.0026	.95	.00003	.000069
Conventional CT	3500	475	54.6	12,000	.014	.00124	.00003	.0016	1.145	.00003	.0004
Dual Fueled Engine	500	475	54.6	9,200	.023	.010	.0001	.0322	1.20	.0009	.00046
Otto/Spark Engine	500	425	48.9	9,700	.027	.0032	.00001	.008	.97	.0017	.000475
Diesel Engine	500	410	47.2	7,800	.025	.017	.005	.010	1.70	.002	.003

* Utility

Table 3. Peaking Distributed Generation Technologies' Cost, Performance and Emissions, 2010

Distributed Generator Type	Power (kW)	Installed Cost		Heat Rate	Variable O&M	Emissions lb/kWh					
		$/kW	$/kW-yr*	Btu/kWh	$/kWh	NO_x	SO_x	CO	CO_2	VOC	PM
Microturbine	45	400	46.0	12,000	.01	.001	.00003	.00255	1.10	.000045	.00008
ATS	4200	425	48.9	9,500	.01	.000105	.000021	.0026	.95	.00003	.000069
Conventional CT	3500	400	46.0	10,500	.01	.0011	.00002	.00133	1.00	.00003	.0004
Dual Fueled Engine	500	450	51.8	8,600	.02	.005	.0001	.0291	1.00	.0005	.00034
Otto/Spark Engine	500	425	48.9	9,700	.025	.0026	.00001	.008	.97	.0015	.0003
Diesel Engine	500	410	47.2	7,800	.025	.017	.005	.010	1.70	.002	.003

* Utility

Table 4. Baseload Distributed Generation Technologies' Cost, Performance and Emissions, 2002

Distributed	Power	Installed Cost		Heat Rate	Variable O&M	Emissions lb/kWh					
Generator Type	(kW)	$/kW	$/kW-yr*	Btu/kWh	$/kWh	NO_x	SO_x	CO	CO_2	VOC	PM
Microturbine	45	575	66.1	12,000	.01	.00115	.00003	.00265	1.18833	.00004	.00009
ATS	4200	450	51.8	9,500	.01	.000211	.000021	.0026	.95	.00003	.000069
Conventional CT	3500	540	62.1	11,450	.009	.00124	.00003	.0016	1.145	.00003	.0004
Dual Fueled Engine	475	525	60.4	8,700	.02	.010	.0001	.0322	1.20	.0009	.0005
PEM Fuel Cell**	500	1,000	115.0	9,500	.022	.000015	.000	.000	.95	.0009	.000
PhosAcid Fuel Cell**	250	1,720	197.8	8,530	.015	.000015	.000	.000	.85	.000	.000

* Utility
** Natural Gas Fuel

Table 5. Baseload Distributed Generation Technologies' Cost, Performance and Emissions, 2010

Distributed	Power	Installed Cost		Heat Rate	Variable O&M	Emissions lb/kWh					
Generator Type	kW	$/kW	$/kW-yr*	Btu/kWh	$/kWh	NO_x	SO_x	CO	CO_2	VOC	PM
Microturbine	45	475	54.6	11,500	.01	.001	.00003	.00175	1.15	.00004	.000083
ATS	4200	425	48.9	9,500	.01	.000105	.000021	.0026	.95	.00003	.000069
Conventional CT	3500	500	57.5	11,150	.008	.0011	.00002	.00133	1.00	.00003	.0004
Dual Fueled Engine	450	475	54.6	8,500	.018	.005	.0001	.0291	1.10	.0005	.00034
PEM Fuel Cell**	250	918	105.6	7,200	.008	.000015	.000	.000	.72	.000	.000
PhosAcid Fuel Cell**	500	1,168	134.3	8,000	.01	.000015	.000	.000	.85	.000	.000

* Utility
** Natural Gas Fuel

To illustrate this point, Figure 1 shows NO_x emissions for various distributed generator options, including the ATS, at the time of this study. Note, in particular, that NO_x emissions from the ATS are shown to range from 2.5 ppm to 25 ppm. Achieving 25 ppm NO_x levels from the ATS is routinely attainable today with little modification, and achieving 15 ppm NO_x from the ATS is not difficult with current technology. For this study, ATS NO_x emissions were assumed to be 5 ppm in 2002, and 2.5 ppm in 2010, reflecting both the ongoing trends in NO_x reduction technologies and the emissions regulations likely to be in place in California in those years.

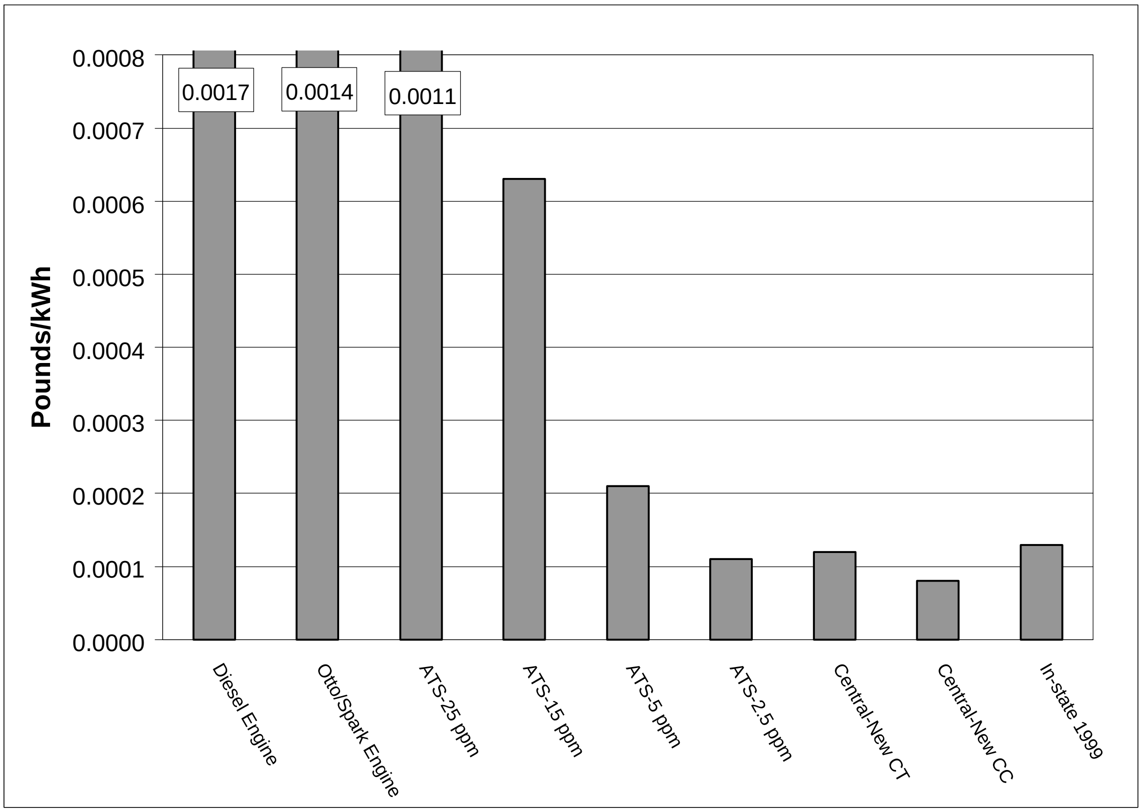

Figure 1. NO_x Emissions from Various Distributed Generators

No attempt was made to reconcile sizes of industrial distributed generators with industrial electric loads. For the most part, this is not an issue because most industrial loads are larger than the typical distributed generator, and most distributed generators are quite modular (though, as unit size decreases, price/cost does increase relative to unit size). In this context, of special note is the ATS whose nameplate capacity is about 5 MW. If an industrial customer's load is less than 5 MW, then, in order to make a 5 MW ATS installation viable, either excess electric energy and/or capacity is sold to another entity, or two or more customers' loads must be aggregated to 5 MW.

Though natural gas is assumed as the fuel for most distributed generators, natural gas fuel may not be available at all sites.

4. Utility Central Station Generation Fuels, Cost and Air Emissions

Generation Fuels and Emissions

The utility's cost to generate and/or price to purchase electricity from central generation and air emissions associated with that electricity are highly dependent upon fuels used. Most in-state generation is nuclear, hydroelectric, gas fired and renewables (biomass combustion, geothermal and wind).

Composite emission factors for the mix of major central generation plants within California are given in Table 6. For this study, distributed generators were assumed to compete against that mix of in-state power generation reflecting a mix of generator types and fuels. National average emissions values are provided, for reference, in Table 7. These values are estimates derived from 1997 EPA data for total national annual emissions from utility generation [13] divided by EIA estimates of total national energy generation [14].

Table 6. California Average Central Generation Emissions, lb/kWh

	NO_x	SO_2	CO	CO_2	PM	VOC
Pounds per kWh*	.00013	.00002	.00017	.20149	.00002	.00011

* Source: California Energy Commission

Table 7. 1997 National Average Central Generation Emissions, lb/kWh

	NO_x	SO_2	CO	CO_2	PM	VOC
Pounds per kWh	.00343	.00687	.00026	1.16	.00017	.00003

Utility Avoided Cost Assumptions

Shown in Table 8 are electric utility avoided costs for generation capacity and variable operations cost, transmission and distribution facilities, and outages associated with load growth (i.e., new load). For both baseload and peak generating capacity (G) and energy, market based values are used; that is, these are the values that a utility would expect to pay to generating companies in a deregulated, market-based environment. For this study, these values were obtained from the PG&E, SCE and SDG&E utility tariffs [15, 16, 17]. Avoided transmission and distribution costs are based on the anticipated utility budgets for these infrastructure improvements in order to serve the expected load growth. (Please see Appendix A. Utility Operational and Avoided Cost Assumptions for more details about utility avoided cost assumptions.)

It is important to note that generation, transmission, and distribution capacity costs are assumed to vary. The range of costs for utility baseload and peaking generation is modeled as a "triangular distribution" of costs whose high and low values are shown in the table. Transmission and distribution (T&D) capacity costs vary from one location to another. That variation is represented by a spread of total cost values, as explained in detail in Section 5. Utility Avoided Cost Evaluation.

Table 8. Key Central Generation Avoided Cost Values

Base G Capacity ($/kW-yr)	Peak G Capacity ($/kW-yr)	Base Energy ($/kWh)	Peak Energy ($/kWh)	T Capacity ($/kW-yr)	D Capacity ($/kW-yr)	Outages ($/kW-yr)
70 - 90	25 - 30	.0025	.004	5.03	18.03	7.5

Utility Avoided Cost: Caveats and Considerations

As with the economic calculations for this evaluation, it could be argued that distributed generators would compete against new central generation plants that would have to be built in the absence of distributed generation. However, that assumes that distributed generators would only be deployed in situations that offset need for new central supply.

In reality, if distributed generators were deployed, they would probably offset some new central power plant construction as well as some expensive generation from older, less efficient central generators. This is an important point in this context, because new central station combined-cycle generation plants tend to be more fuel-efficient and to produce fewer emissions than the composite of all power plants, including older, less efficient and dirtier plants.

For this study, in-state electricity sales were not reconciled with in-state electric energy generation. That is, all distributed generation was assumed to compete against the average in-state plant (i.e., average with regard to emissions).

5. Utility Avoided Cost Evaluation

Methodology and Assumptions

Calculation of economic market potential for utility owned and operated distributed generation is based on economic criteria that electric utility planners and engineers would use to evaluate the costs and benefits associated with use of distributed generators. (The PG&E publication RESOURCE: An Encyclopedia of Utility Terms [18] contains a wealth of definitions and additional information for many of the terms used in this analysis.)

As illustrated in Figure 2, to make the economic market potential estimates, the DUVal model [2] compares:

- a statistically defined range of possible annualized avoided cost (i.e., **benefits**) associated with use of the distributed generator

  to:

- the utility's annualized net cost to own and operate a distributed generator, cost-of-ownership[2] (**cost**).

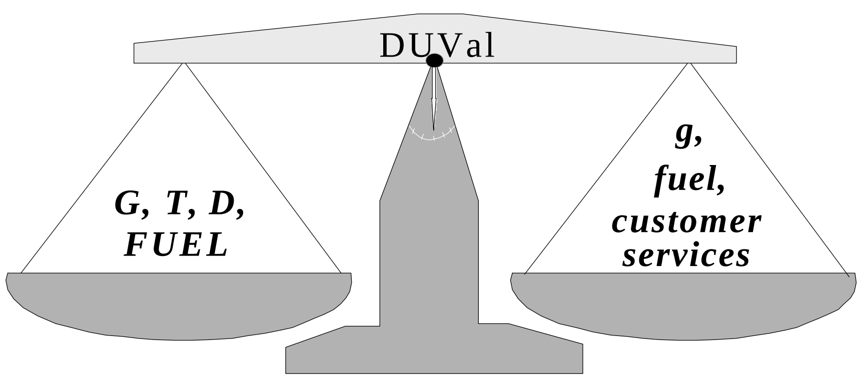

Figure 2. DUVal Evaluation—Utility Perspective

Cost-of-ownership includes purchase, installation, financing, depreciation expenses, taxes, fuel, maintenance, and fixed costs such as periodic overhauls and insurance.

Utility benefits associated with the use of distributed generators are utility/grid-related costs that will not be incurred by the utility (i.e.; are an "avoided cost") if the distributed generator is used in lieu of the central/grid solution. This assumes, of course, that the distributed generator can provide the same or better service reliability and power quality. In other words, for the utility, the benefit associated with use of a distributed generator is

[2] Net of costs incurred and benefits (e.g. sales of electric or heat energy) accrued.

the avoided cost for otherwise needed fuel, O&M and overhead expenses and generation, transmission and distribution capacity (equipment) costs.

(Note that even if a project is merely deferred rather than avoided altogether, the time value of money often makes it worthwhile to use a temporary, redeployable, modular, and less financially risky distributed generation option rather than a more typical grid upgrade.)

Variability of Utility Avoided Cost

The DUVal model uses a statistical representation of the *range* of utility avoided costs throughout the service area and among locations. Utility avoided costs, defined as those costs avoided if distributed generators are used in lieu of the conventional central generation and wires option, vary widely among utilities and even within a given utility's service territory. Some locations are inexpensive to serve and others can be quite expensive to serve. These costs are modeled in DUVal as statistical distributions referred to as "value mountains" because of their characteristic shape (shown in Figure 3).

Underlying assumptions that are used to create value mountains are shown in Table 8. These ranges of values represent the statistical variation of electric utility total avoided costs to meet new load. Components are generation capacity and generation variable costs, transmission and distribution facilities, and outages. These are costs associated with serving new load associated with load growth. (Appendix A includes details about utility avoided costs.)

Avoided costs for generation, transmission, and distribution capacity to serve new load are parameters that are assumed to vary, resulting in the variation that underlies the value mountain as shown in the example in Figure 3. The range of costs for utility baseload and peaking generation are modeled as a "triangular distribution" of costs whose high and low values are shown in Table 8. T&D capacity costs vary from one location to another in a more complex manner. These data ranges were derived from recent historical utility data in the Energy Information Administration's Electric Power Annual, 1996 [18].

Determination of Economic Market Potential

The total cost to implement a distributed generation option is compared to the value mountain of avoided costs. The economic market potential for a given distributed generation technology corresponds to the total number of locations that are more expensive to serve with central generation than with the distributed technology being analyzed.

Economic market potential is expressed in percent of the total market (total market in this context being the technical market potential, or, all MW/year of load in play, described in the next section of this report).

In the example, consider point **a**; assume it indicates the cost (in $/kW-yr) to own and operate a distributed generator. Point **b** indicates the portion of utility avoided cost that is higher and lower than that for the distributed generator being considered. Point **c** indicates the economic market potential—the portion of load growth for which the distributed generator cost is lower than the grid solution composed of central generation and T&D enhancement. In the example the distributed generator's cost is lower than about 29% of the situations, statistically speaking. If load growth was 1,000 MW then the economic market potential is 290 MW.

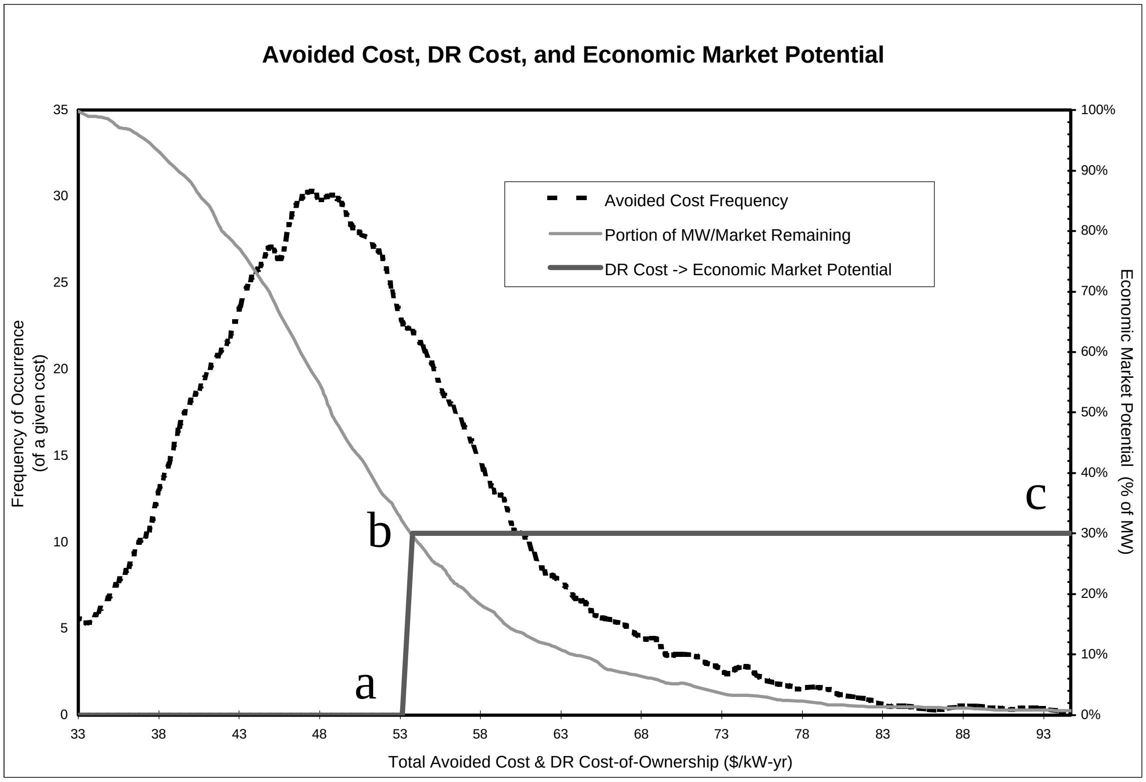

Figure 3. Statistical Spread of Utility Total Avoided Cost and Economic Market Potential ("Value Mountain")

Utility Operational Modes: Peaking and Baseload

Quantitative economic market potential estimates are made for both peaking and baseload operation modes. The distributed generation is assumed to be sited at substation and feeder locations (i.e., at or near loads), thereby capturing the benefit of avoided transmission and distribution costs.

To serve as a **peaking** resource, a distributed generator must reduce utility infrastructure capacity needs. That, in turn, requires distributed generation to be operational during the utility's peak demand hours: the 100 to 200 hours during the year when demand for electricity is highest. The level of power draw on the utility system from all customers during those times dictates the required maximum capacity of the utility's generation system.

This concept is important for the analysis because the degree to which a distributed generator allows the utility to avoid procurement of additional capacity determines the "capacity benefit" associated with distributed generation. Stated another way, to the extent that distributed generators operate to offset the need for new/upgraded utility electric grid capacity, they receive a capacity credit commensurate with the amount of otherwise needed utility generation, transmission and/or distribution equipment (capacity, infrastructure). Note that because peaking distributed generators operate for so few hours per year, their total variable operating costs in the evaluation are much less than their total capital costs.

Baseload distributed generators operate for thousands of "full load equivalent" hours per year, in this case about 4,700 hours. They can also receive the capacity credit described above if they generate during the utility's peak demand hours. But for baseload distributed generators, it is usually more important to consider their cost of production for electric or thermal energy.

Because they operate for many hours per year, baseload distributed generators must compete primarily on an "energy" (i.e., variable) cost basis. (By contrast, the key criterion of merit for peaking units is "capacity" cost, a fixed cost.) During most of the year, the competition for baseload distributed generators is lower-cost commodity electricity from the wholesale electric marketplace. That marketplace is dominated by large generation facilities with economies of scale and generally low incremental cost of production.

Therefore, installed capital cost and cost of production are both key criteria driving a baseload distributed generator's economic competitiveness. In turn, a baseload distributed generator's net cost of production is driven by fuel efficiency, fuel price, variable operations and maintenance costs for the particular distributed generator, and the degree to which waste heat can be sold for cogeneration.

Utility Locations: Substation and Feeder

As depicted graphically in Figure 4, DUVal evaluates distributed generators at two location types: at a utility substation and on a distribution feeder at or near a customer's site.

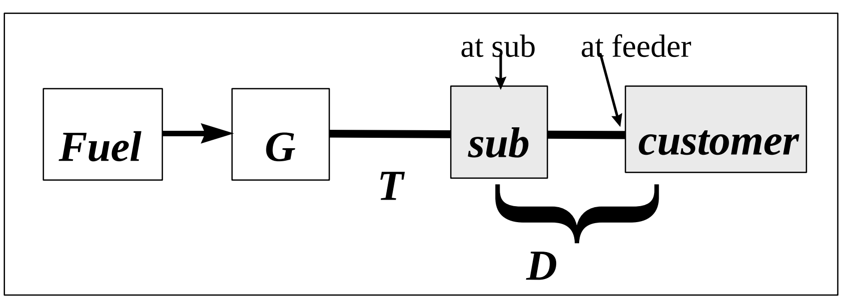

Figure 4. DUVal Evaluation Nodes

Several factors distinguish these two types of locations; key ones are:

- Because most electric service outages occur between the substation and the load, a distributed generator sited at the substation does not receive as substantial a credit for reliability increases as does a distributed generator located on the feeder or at the customer's site.
- Distributed generators at substations do not defer the need for a feeder and thus do not receive an avoided cost credit for the cost of a feeder.
- Distributed generators at a substation are assumed to be larger and to qualify for purchase of gas at a wholesale/power plant procurement price; distributed generators on the feeder are assumed to use gas whose prices are higher because purchases are at a lower-volume, "retail" level.

It is assumed that the required fuel type and distribution infrastructure are available at all sites considered.

Utility Evaluation MegaWatts "In play"

The maximum potential size of the market (technical market potential) for distributed generation is assumed to be the total load growth in units of MegaWatts per year (MW/year) – the MegaWatts "in play" each year. Load growth in California is about 2.0% per year. Table 9 shows the expected load in GW and the load growth in MW for the years 1999-2003 and 2010 (data supplied by the California Energy Commission).

Table 9. California Total Load and Load Growth

Year	1999	2000	2001	2002	2003	2010
Load (GW)	46.9	47.9	48.8	49.8	50.8	58.3
Load Growth (MW)	–	938	957	976	996	1,144

Source: California Energy Commission

Note that no "embedded" load is considered to be in play; only the annual <u>increase</u> in total load (load growth) is assumed to be in play. This is reasonable because it is unlikely that existing capacity with a useful life will be removed or decommissioned.

Utility Distributed Generation Economic Market Potential and Emissions Impacts

Peaking Mode Distributed Generation Results

Economic Market Potential and Emissions Implications

Economic market potential for peaking distributed generators is shown in Table 10 and Table 11 in the columns labeled "Portion of Growth," for the years 2002 and 2010, respectively. The first data row in each table, labeled "System Only," represents the case in which all load growth is served by existing central generation, i.e., no distributed generation is installed. The following six data rows show the total air emissions that would result from the mix of generation: cost-effective distributed generation at the market share shown, plus power supplied by the grid for the balance of the load growth.

Emissions are stated in tons per year. It is helpful at this point to remember that emissions due to peak load operation are for production of electricity needed to serve load added within the given year, i.e., for load growth (also referred to in this study as "load in play"). Furthermore, emissions are for generation during 200 hours in a year.

Table 10. Peak Load Central and Distributed Generation Economic Market Potential and Air Emissions, 2002

2002 Peaking Distributed Generator Option	Portion of Growth (%)*	Tons of Emissions					
		NO_x	SO_x	CO	CO_2	VOC	PM
System Only	100.0	13.2	2.0	173	20,485	2.0	11.2
Microturbine	28.7	44.4	2.3	203	49,620	2.7	10.5
Adv. Turbine System (ATS)	57.7	17.5	2.1	220	62,165	2.6	8.6
Conventional Comb. Turbine	32.1	47.8	2.3	167	49,782	2.3	20.1
Dual Fuel Engine	36.8	367.5	4.9	1,266	56,047	33.6	23.6
Otto/Spark Engine	54.1	175.0	1.5	502	60,620	90.7	30.2
Diesel Engine	75.5	1,256	368.9	779	130,288	148	224

* Load growth = 976 MW/yr

Table 11. Peak Load Central and Distributed Generation Economic Market Potential and Air Emissions, 2010

2010 Peaking Distributed Generator Option	Portion of Growth (%)*	Tons of Emissions					
		NO_x	SO_x	CO	CO_2	VOC	PM
System Only	100.0	15.5	2.4	239	24,032	2.4	13.1
Microturbine	75.3	90.0	3.2	279	100,776	4.5	10.1
Adv. Turbine System (ATS)	70.3	13.1	2.4	280	83,606	3.1	9.4
Conventional Comb. Turbine	79.0	102.8	2.3	170	95,502	3.2	38.9
Dual Fuel Engine	52.0	305.1	7.1	1,847	71,075	30.9	26.5
Otto/Spark Engine	54.5	169.3	1.7	608	71,465	94.7	24.7
Diesel Engine	74.8	1,460	428.8	917	151,654	172	260

* Load growth = 1,144 MW/yr

Figures 5 and 6 show the market potential in MW for peaking distributed generators in 2002 and 2010, respectively.

Utility Peaking Mode Distributed Generation Results, Observations

When considering the results, recall that peaking distributed generators operate during the utility's peak demand hours: the 200 hours during the year when demand for electricity is highest. This is done primarily to avoid the need for additional utility equipment or infrastructure (i.e., capacity) and related costs.

Note that peaking distributed generators would tend to be deployed almost exclusively at feeder locations. This is driven by the fact that generation resources located near loads provide a significant reliability improvement. Because the majority of power outages occur when power distribution lines are affected, distributed generators can provide a signifcant boost to reliability if they are "downstream" from the outages.

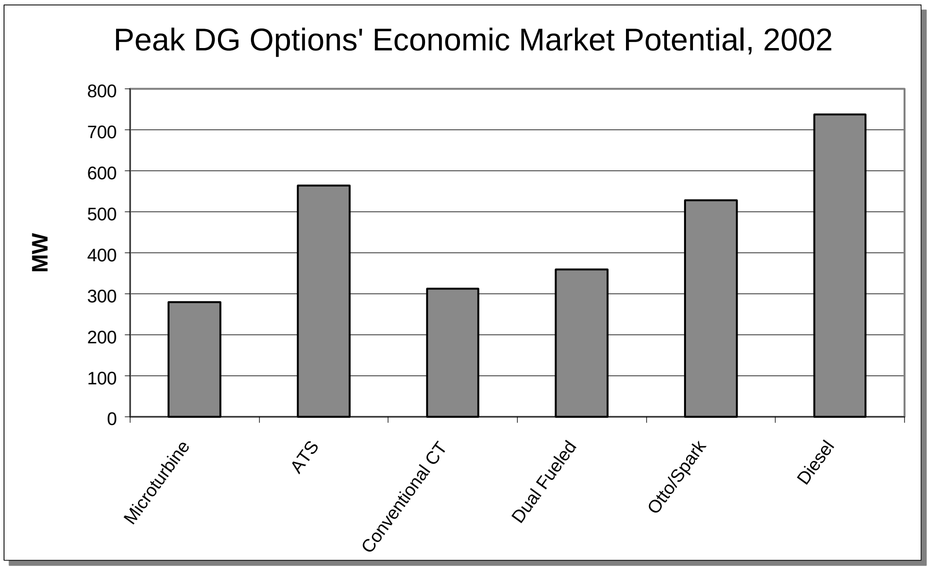

Figure 5. Market Potential for Utility Peak Distributed Generation in 2002, MW

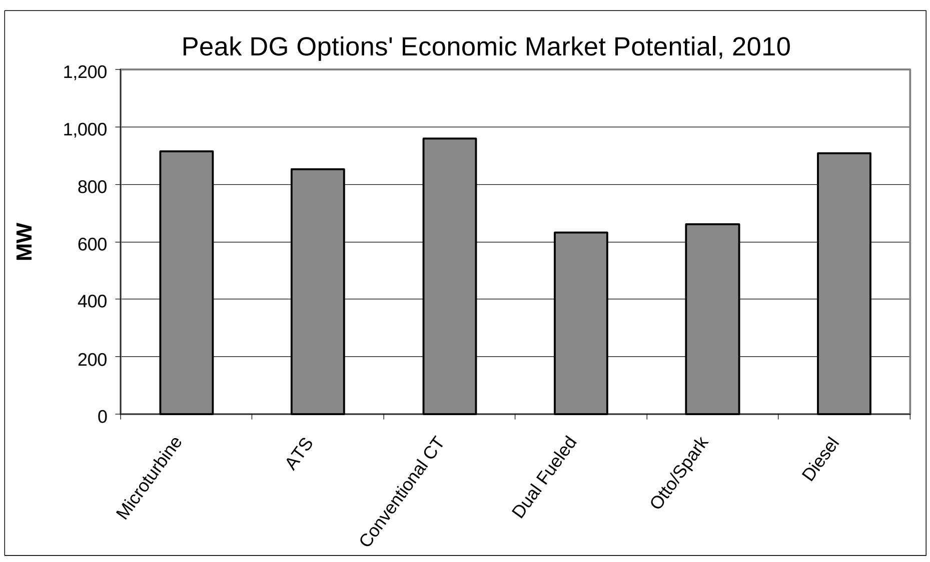

Figure 6: Market Potential for Utility Peak Distributed Generation in 2010, MW

Baseload Mode Distributed Generation Results

Economic Market Potential and Emissions Implications

Estimated economic market potential and emissions for utility baseload distributed generators is given in Tables 12 and 13, for the years 2002 and 2010 respectively. Values in the first data column are the economic market share estimates for each distributed generator type, expressed in per cent of the load growth for that year. Values in the remaining columns are the air emissions, in tons, that would result from the generation mix specified by either: central generation only (first row), or distributed generation technology at the specified market portion plus central generation for the balance of the load growth.

Table 12. Baseload Central and Distributed Generation Market Potential and Air Emissions, 2002

2002 Baseload Distributed Generator Option	Portion of Growth (%)*	Tons of Emissions					
		NO_x	SO_x	CO	CO_2	VOC	PM
System Only	100.0	315.5	48.5	4,126	488,993	48.5	267.0
Microturbine	4.4	419.5	49.5	4,216	589,295	50.5	264.4
Adv. Turbine System (ATS)	32.9	373.1	49.0	4,761	1,056,296	55.8	231.9
Conventional Comb. Turbine	10.4	583.1	50.8	4,084	715,572	50.8	336.1
Dual Fuel Engine	0.1	338.5	48.7	4,197	491,300	50.6	267.9
PEM Fuel Cell	0.0	315.5	48.5	4,126	488,993	48.5	267.0
Phosphoric Acid Fuel Cell	0.0	315.5	48.5	4,126	488,993	48.5	267.0

* Load growth = 976 MW/yr

Table 13. Baseload Central and Distributed Generation Market Potential and Air Emissions, 2010

2010 Baseload Distributed Generator Option	Portion of Growth (%)*	Tons of Emissions					
		NO_x	SO_x	CO	CO_2	VOC	PM
System Only	100.0	370.1	56.9	5,694	573,665	56.9	313.2
Microturbine	13.7	693.9	60.4	5,569	925,693	64.1	301.5
Adv. Turbine System (ATS)	42.0	335.6	57.6	6,287	332,726	67.8	260.7
Conventional Comb. Turbine	15.8	786.7	56.6	5,369	914,876	60.9	436.4
Dual Fuel Engine	0.0	370.1	56.9	5,694	573,665	56.9	313.2
PEM Fuel Cell	1.7	364.5	56.0	5,597	597,367	56.0	307.9
Phosphoric Acid Fuel Cell	0.0	370.1	56.9	5,694	573,665	56.9	313.2

* Load growth = 1,144 MW/yr

These results indicate how baseload distributed generators' costs compare with the spread of utility total cost of service, i.e., the cost to meet new load by making necessary additions to the utility infrastructure.

Units for economic market potential are the percentage of the total possible market, (i.e; MW in play, as described above) for which the given distributed generator is cost-effective. Emissions values are expressed in tons of total emissions given the resulting mix of generation: distributed generators at the percentage of load growth specified, plus central generation for the balance of the load growth. Market potential in MW for utility baseload distributed generation in the years 2002 and 2010 is shown graphically in Figures 7 and 8, respectively.

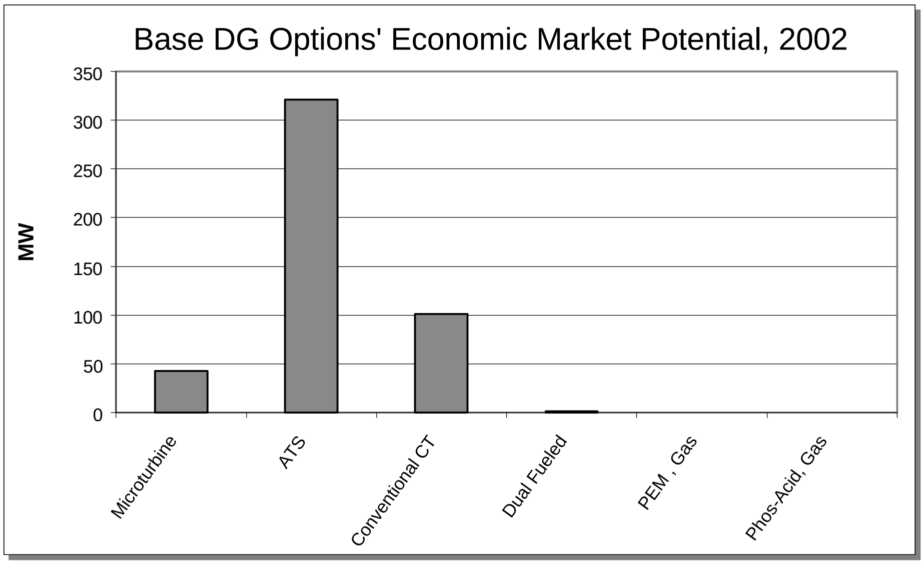

Figure 7: Market Potential for Utility Baseload Distributed Generation in 2002, MW

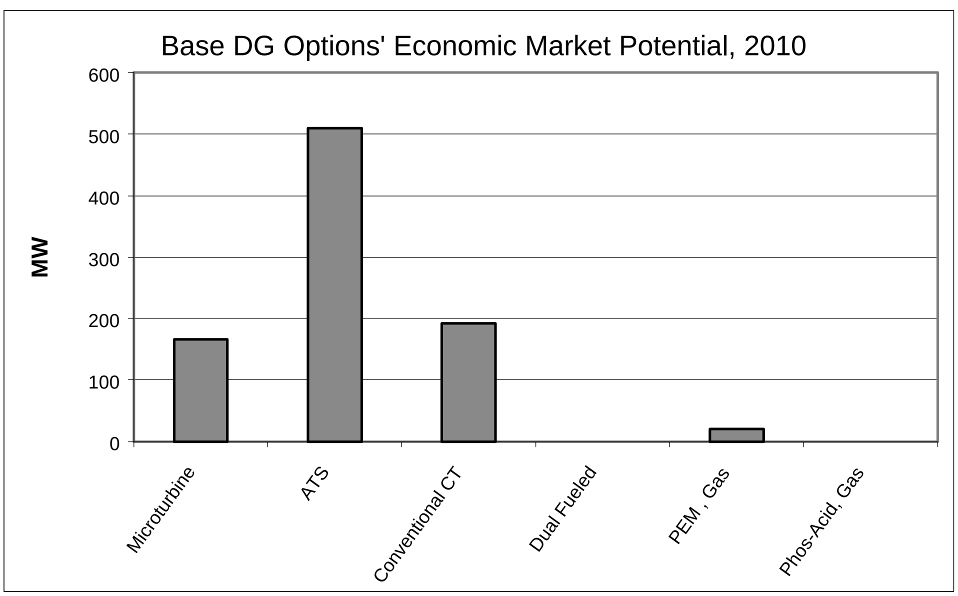

Figure 8: Market Potential for Utility Baseload Distributed Generation in 2010, MW

Utility Baseload Distributed Generation Results and Observations

As a brief review: baseload distributed generators operate during the utility's load hours; in this evaluation, that represents the 4,774 "full load equivalent" hours during the year when virtually all demand for energy occurs.

As discussed above, baseload distributed generators' cost-effectiveness is a function, in part, of their ability to provide electric capacity, when needed. But to be viable, the baseload distributed generators must also generate energy needed over 4,774 full load equivalent annual load hours at a competitive cost. So a baseload distributed generator is cost-effective if it can provide both capacity and energy at a competitive total cost relative to the grid.

Stated another way, distributed generators are deployed by utilities for one or both of two primary benefits:

1) to allow the utility to avoid costs related to adding utility generation, transmission, or distribution equipment/infrastructure (i.e., capacity), and/or

2) to provide cost-competitive energy (primarily electric energy but possibly including mechanical and thermal energy), resulting in reduced overall cost-of-service, and possibly reduced net fuel use and net air emissions.

Note that baseload distributed generators tend to be deployed at substation locations. That is due to the fact that natural gas price is assumed to be significantly higher for feeder locations than for substation locations, for a variety of reasons. Note also that the fuel price advantage at substation locations can be offset, to some degree, by the fact that distributed generators located at substation locations are farther from loads than feeder distributed generators (i.e., they are upstream from most outages) and thus they provide much less of a benefit due to reliability improvement. The one important exception to the fuel cost advantage is when distributed generators are used in CHP applications.

For the evaluation, 15% of load was assumed to be coincident with thermal loads such that a distributed generator with CHP could serve electric and thermal loads. All baseload distributed generators were allowed to serve that market. CHP can only occur at feeder locations, where demand and thermal loads are. CHP is cost-effective if the incremental cost to recover the heat is less than the price that would have been paid to generate the same heat with natural gas.

Utility Distributed Generation Results: Observations

- In an absolute sense, because utility peaking distributed generators would only operate for 200 hours per year and would only address new load (that from load growth), installation of most or all types of peaking distributed generators would add much lower amounts of emissions than baseload distributed generators.
- Diesel engines are the lowest-cost distributed generation option, therefore they are very cost-effective capacity resources.

- Dual fueled engines are the lowest cost baseload distributed generation option, and therefore are cost-effective for many circumstaces.

Utility Distributed Generation Results: Caveats

- Economic market potential estimates are calculated without regard to substitutes. In actuality distributed generators would have to compete against other distributed generators and possibly energy storage, demand side management (DSM) or other conservation resources.
- Electric utility ownership of distributed generation may be prohibited or restricted in some cases, depending on local regulation.
- For gas fired options, economic market potential values may be reduced based on the availability of natural gas fuel at specific locations.
- Economic market potential for peaking and baseload distributed generators were evaluated as solutions for the same "market," that is, all of the forecasted electric load growth. In reality, of course, these are very different applications or market segments with very different needs and decision drivers. Peaking units primarily offset expenditures for fixed capital equipment; baseload distributed generators are used because they result in both reduced need for capital equipment (upstream to bolster the electric grid) and lower overall energy production cost, usually due to lower variable maintenance costs and/or lower fuel cost per kWh produced than for grid-based electricity. Also note that, at some point, these two market segments will begin to overlap.

The following caveats are important as readers consider the results for electric utility owned <u>peaking</u> distributed generators:

- Substantial deployment of Diesel fueled engines may be problematic because of air emissions.
- Non-generation options, such as geographically targeted conservation, demand side management (DSM), or energy storage, may indeed be cost-effective in some situtations for peaking applications. If so, they would compete against generation options evaluated for this study.

The following additional caveats are important to keep in mind when considering the results for <u>baseload</u> generators:

- Substantial deployment of dual fueled engines may be problematic because of air emissions, especially NO_x.
- If electric utility ownership of distributed generators is restricted, it is likely to be based on the amount of energy generated rather than the amount of capacity added. This may make baseload distributed generators unattractive despite being cost-effective in a strictly financial sense.

6. Customer Evaluation and Bill Analysis

Methodology and Assumptions

Methodology Overview

The customer bill analysis was undertaken using DUA's DUVal-C model. It minimizes the annual cost incurred by an electric utility customer to serve a given kW of electric load. The bill analysis is a comparison of the cost to purchase all electricity versus the cost to own and operate a distributed generator to generate some or all of the electricity needed. The concept is illustrated in Figure 9 (see also the DUA report to ORNL and EPA, titled Analysis of the Economic and Environmental Benefits of Market Penetration of Distributed Generation [19]).

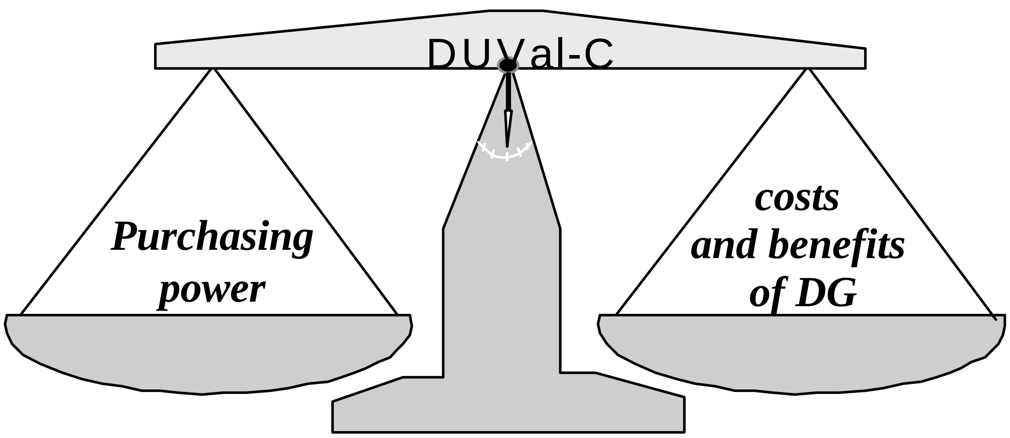

Figure 9. DUVal-C Evaluation

In other words, some or all electricity may be purchased either from the electric utility or customers may produce equivalent (or better) electricity on-site with distributed generation. The "make-or-buy" decision is made by first calculating the annualized costs of the two options (utility service or distributed generator ownership and operation), and then estimating the portion of customer load hours for which distributed generation is cost-competitive.

Cost for both options, *make* (use distributed generation) or *buy* (purchase from utility), are calculated with consideration given to a wide range of customer decision criteria, mostly financial. Key criteria include cost of capital (for financing the distributed generator), payback period required, electric service outage costs, and the reliability of both the grid and the distributed generation technologies. Details are given below.

Key Parameters and Assumptions

The dataset required for a bill analysis is comprehensive. Categories of inputs include:

- customer financials such as cost of capital
- electric energy price and demand charges for each of three time periods (on-peak, mid-peak, and off-peak) for each of twelve months (a total of 36 utility electricity "price periods" within the year)
- customer electric energy use and peak demand for power during each (of 36) utility electricity price periods
- fuel prices and distributed generator fuel efficiency
- distributed generator variable O&M
- distributed generator equipment cost

Also important for this evaluation are:

- emissions from the distributed generators
- electric load and energy use that can be served by distributed generators

Customer Financials

DUVal-C uses an annuity representation of the carrying cost for the capital equipment. That annualized cost is a function of the cost for the equipment, customer federal and state income tax rates, customer cost of capital (that is, in turn a function of debt interest rate, and return on investment for non-debt capital), and depreciation. (See also the DUA report to the National Renewable Energy Laboratory [20]).

For this study, the customer uses 50% debt financing with a 10% per year interest rate and 50% owner financing requiring a 20% return. The Federal income tax rate is assumed to be the marginal rate of 34% and the state tax rate is the marginal rate of 8.8%. The equipment is depreciated over five years for tax purposes, and the life is assumed to be 20 years. Customers typically seek rapid return on their investments, hence the rapid depreciation.

Given those assumptions, the resulting annualization factor is 0.2169. It is used as follows: For a distributed generator whose installed cost is $500/kW, the annual "carrying cost" associated with financing and depreciation of distributed generator equipment is $500 * 0.2169 = $108.50/kW-year. Again, this covers the cost to finance and depreciate the distributed generator equipment; it does not include any variable cost associated with the operation of the plant.

Utility Prices and Price Periods

A key consideration for the bill analysis is the utility price for electricity. Primary components are: 1) price for electric energy, reflecting utility variable cost incurred to generate electricity, comprising mostly fuel and O&M expenses; and 2) demand charges reflecting the utility's fixed costs for delivery of electricity. For summaries of the tariffs used in this study, please see Appendix B. Tariff Summaries, Customer Demand and Energy Use.

Underlying the customer's electric utility bill are the rates or tariffs that specify the prices charged for energy and demand. Energy prices are denominated in units of $/kWh and apply to each kWh used by the customer. Demand charges are typically specified in units of dollars per kW per month ($/kW-mo), and are applied to the maximum customer demand for power (units of kW) during the month.

Energy price and demand charges can vary according to the time of day and the month. Therefore electric energy price is specified for each of three time periods (on-peak, mid-peak and off-peak) for each of twelve months (a total of 36 "price periods" within the year). Peak demand charges are specified for on-peak and mid-peak price periods for each of twelve months.

On-peak electric energy is used by consumers during times when a utility's electricity production is greatest, usually during afternoon hours on hot summer days and during the early evening hours on cold winter days. It is more expensive than the average price for electricity (and for off-peak electric energy) because peaking power plants, as a class, tend to be less efficient and their non-fuel operating costs, especially for O&M, higher than baseload plants.

Mid-peak and off-peak electric energy from the utility is less expensive because more fuel-efficient baseload generators generate it. Thus, the price tends to be lower than for on-peak electricity. Many baseload generators also have lower non-fuel operation and maintenance costs than peaking generators. In some cases, the price for off-peak utility electricity is affected by the fact that many generators are designated as "must run" units. A generator could be designated "must run" for any of several reasons, including: 1) transmission system operation constraints, 2) it is not economic to reduce plants' power output below certain levels, or 3) it is not practical to shut them down altogether for just a few hours because of cost and wear and tear associated with restarts. The availability of low-cost power from baseload utility plants during off-peak, and possibly mid-peak, price periods helps to keep average annual prices low.

Demand charges address fixed costs incurred by the utility for plant and equipment required to supply electric energy to end-users. (By contrast, the price for electric *energy* reflects the utility's variable expense to generate the electric energy, mostly fuel for fossil fueled plants.) This capacity (and electric demand) is expressed in units of power (kW).

Each large customer's peak demand (maximum power draw) is measured each month. A demand charge ($/kW-month) is applied to each unit of maximum electric demand (kW) that occurs within each demand price period. (Price periods vary by time-of-day and by month). If distributed generators operate during periods when the demand charge applies, the customer can minimize the demand charges, which is a benefit in the bill analysis context.

Note that there are usually at least two entities that impose energy and demand charges: 1) the electricity supply organization that provides the electric energy as if it were a "commodity" and 2) the organization that transmits and distributes the electricity.

For this study, tariffs for the three largest investor owned utilities were considered (note distinction between approved and proposed):

- Pacific Gas and Electric's E20 (proposed 10/99) [15]
- Southern California Edison's (SCE) TOU-8 RTP (proposed 1/00) [16]
- San Diego Gas and Electric's (SDG&E) A6 Time of Use (existing) [17]

Tariffs considered were all for customers whose annual maximum electric load exceeds 500 kW. They reflect the range of expected "post deregulation" prices statewide. Please note that tariffs do not include charges for standby service, exit fees, etc.; these may apply in the future in many cases.

Customer Electricity Use: Amounts and Timing

Customer loads are assumed to have a 0.8 annual average electric load factor (i.e., energy use occurs, on average, 80% of the time during a year (a measure of the rate of energy use for each kW of load connected).

As noted above, customer demand (for power, kW) and electric energy (kWh) use varies during the year. During hours of peak operation, a facility's electric demand and the rate of electric energy use is at a maximum. During "off peak" hours (e.g.; during weekends and late at night) the maximum hourly demand is often considerably lower than the facility's peak hourly power draw as is the average rate of energy use.

For details about time-specific customer demand and energy use please see Table 25 of Appendix B.

Distributed Generator Cost and Performance

Table 14 shows key elements of total cost for the six distributed generators evaluated for the customer perspective part of the analysis. Note that two distributed generators were evaluated as CHP plants, the Microturbine and the ATS. An additional $230 per kW is added to the cost of the distributed generator for the equipment needed to capture waste heat (pipes, pumps, tanks, etc.).

Fuel Prices

Fuel for distributed generation will be obtained from the local gas utility or from fuel suppliers. Natural gas price is determined by the amount purchased. For this evaluation, the customer is assumed to be eligible for city gate prices, as described in Fuel for Distributed Generators in Section 3.

Customer Benefit/Cost Evaluation

As described above, a bill analysis is a comparison of the cost to purchase some or all electricity from the utility grid, versus the cost to own and operate a distributed generator to provide comparable service. The decision to make or buy is made by comparing annualized cost for the two options to estimate the portion of customer load hours for which distributed generation is cost-competitive.

The make or buy decision is based on month-specific time-of-day prices for electricity from the grid. For each of three daily price periods in each of twelve months (i.e., 36 price periods per year) DUVal-C chooses the lower of:

- the cost to <u>make</u> power using an on-site distributed generator,

or

- the cost to <u>buy</u> power from the grid to meet electricity requirements

Table 14. Cost and Performance Summary for Distributed Generators Evaluated for Customer Applications

2002				
Type of Distributed Generator	**Heat Rate (Btu/kWh)**	**Non-Fuel Variable O&M (¢/kWh)**	**Total Installed Cost ($/kW)**	**Annualized Equipment Cost ($/kW-yr)****
Microturbine	12,100	1.0	575	124.7
Microturbine with CHP*	12,100	1.0	805	174.6
Diesel Engine	7,800	2.5	410	88.9
ATS with CHP*	9,500	1.0	770	167.0
Spark Gas Engine	9,700	2.3	475	103.0
Phos. Acid Fuel Cell	8,800	1.8	1,880	407.8

* Incremental capital costs for CHP = $230/kW
**Using fixed charge rate ("annualization" factor) of 0.2169.

2010				
Type of Distributed Generator	**Heat Rate (Btu/kWh)**	**Non-Fuel Variable O&M (¢/kWh)**	**Total Installed Cost ($/kW)**	**Annualized Equipment Cost ($/kW-yr)****
Microturbine	11,500	1.0	475	103.0
Microturbine with CHP*	11,500	1.0	805	152.9
Diesel Engine	7,600	2.5	410	88.9
ATS with CHP*	9,500	1.0	655	142.1
Spark Gas Engine	8,500	2.1	475	103.0
Phos. Acid Fuel Cell	7,200	0.8	918	199.2

* Incremental capital costs for CHP = $230/kW
**Using fixed charge rate ("annualization" factor) of 0.2169.

If, during a given price period the incremental/variable cost of production for the distributed generator is lower than the equivalent power from the grid, then the distributed generator is "dispatched." If not, electricity is purchased from the grid. Thus, dispatch is based on the difference between the *incremental* cost for electricity from the distributed generator and the cost to purchase electricity from the grid. DUVal-C then makes an inventory of the emissions that would occur given the distributed generator's economic dispatch.

Once the annual economic dispatch is determined, the total benefit/cost ratio for the distributed generator option is calculated. DUVal-C adds the capital equipment-related cost to the incremental/variable cost incurred for distributed generator operation during the annual hours of economic dispatch.

Finally, the customer's total cost to own and operate the distributed generator is compared to the avoided cost associated with not having to purchase equivalent electricity from the grid. The result is the total benefit to cost (B/C) ratio. If the avoided bill (benefit) is greater than the total cost to own and operate the distributed generator (cost), then the benefit/cost ratio exceeds 1 and the distributed generator installation under consideration is economically competitive.

Bill Analysis Load "In Play" and Determining Economic Market Potential

As indicated in Table 15, for this study it is assumed that about 20% of electricity use is by large institutional users. Therefore, in 2002 there will be about 49.8 GigaWatts (GW) of total load statewide; 20% of that is about 10 GW of load "in play", i.e., eligible to be served by distributed generation. In 2010 total load in California is about 58.3 GW, 20% of which is 11.7 GW of load in play.

Table 15. California Load Growth, Total Load, and Portion of Load from Large Institutional Users

Year	1999	2000	2001	2002	2003	2010
Load (GW)	46.9	47.9	48.8	49.8	50.8	58.3
Load Growth (MW)	–	938	957	976	996	1,144
Institutional Load (GW)	9.4	9.6	9.8	10.0	10.2	11.7

Source: California Energy Commission

If a distributed generator is cost-effective (i.e., the benefit cost ratio exceeds 1), then in theory it is cost-effective for all load in the region of the state for which the price (tariff) applies (the respective utility's service area). For example, if a microturbine has an overall B/C ratio greater than 1, then assuming that all customers in the large industrial and institutional classes in the same utility service area use the same amount of electricity at the same times, microturbines are cost effective for all such customers in the region for which the tariff price applies.

Emissions from Cost-Effective Operation of Distributed Generation

After determining the economic hours of operation and the overall benefit/cost relationship for each distributed generator, DUVal-C inventories total emissions, both for the central-generation-only situation (no distributed generation), and for the economically optimal mix of cost-effective distributed generation and central generation (i.e., power and electricity are purchased from the grid when doing so is less expensive). Results are stated as the change in per cent, relative to the central-station-only scenario.

Based on the load in play, a calculation is made of the total regional change in emissions if distributed generators were used for economic dispatch (irrespective of total benefit/cost and thus economic viability). Emissions are allocated to respective Air Districts using the Load Intensity Factor.

Bill Analysis Results

Bill Analysis Results

Table 16 contains benefit/cost and economic annual run-times for the customer bill analysis. When considering results, readers should remember that economic run-hours are based on the variable costs of distributed generators, without regard to the purchase cost of the equipment. Of course, the distributed generator would not be installed if the total cost, including plant capital equipment costs, exceeded the cost to purchase electricity from the utility (i.e., project B/C < 1).

Table 16. Economic Run-times and Total Benefit/Cost Ratios for Customer-Owned Distributed Generators, Three Utilities' Tariffs, 2002 and 2010

2002	SDG&E		SCE		PG&E	
DG Type	Economic Run-Hours	B/C	Economic Run-Hours	B/C	Economic Run-Hours	B/C
Microturbine	3,497	1.09	881	0.60	599	0.53
Microturbine CHP	7,032	1.26	4,068	0.75	2,791	0.67
Diesel	3,497	1.07	881	0.71	599	0.65
ATS-cogen	7,032	1.41	7,073	0.90	4,807	0.81
Gas Spark	3,497	1.10	881	0.67	599	0.60
Fuel Cell	3,497	0.57	881	0.23	599	0.19

2010	SDG&E		SCE		PG&E	
DG Type	Economic Run-Hours	B/C	Economic Run-Hours	B/C	Economic Run-Hours	B/C
Microturbine	3,497	1.20	881	0.70	599	0.62
Microturbine CHP	7,032	1.35	4,068	0.82	2,791	0.73
Diesel	3,497	1.06	881	0.71	599	0.65
ATS-cogen	7,032	1.43	7,073	0.91	4,807	0.83
Gas Spark	3,497	1.19	881	0.70	599	0.62
Fuel Cell	7,032	1.07	2,509	0.61	2,791	0.57

Therefore, run times (and resulting emissions) in the tables are estimated based only on the incremental cost to operate the distributed generator. They indicate run times for and emissions from distributed generators whose installed cost is low enough to yield a total project B/C >1.

Tables 17 and 18 show air emission impacts if distributed generators are used for the number of economic run-hours indicated in Table 16. Results are shown for the three prices (i.e., utility tariffs) considered, for years 2002 and 2010.

Table 17. Change in Air Emissions for Distributed Generation Economic Run-Hours, for Bill Analysis Using PG&E /Low Priced Tariff, 2002 and 2010

2002 Technology	Operation Hours Per Year	Electricity Fraction (Portion of Electricity)	Total B/C Ratio	Emissions % Change, Relative to In-state, Average Central Generation Only: NOx	SOx	CO	CO_2	VOC	PM
Microturbine	599	7.7%	.51	+60%	+2%	+112%	+36%	+8%	-2%
Microturbine w/CHP	2,976	38.4%	.67	+34%	+3%	+192%	+11%	-32%	-20%
Diesel	599	7.7%	.63	+953%	+1,828%	+421%	+54%	+764%	+185%
ATS w/CHP	5,126	66.2%	.82	-60%	-8%	+293%	+16%	-40%	-38%
Gas Spark	599	7.7%	.59	+190%	-4%	+335%	+29%	+764%	+24%
Fuel Cell	599	7.7%	.18	-7%	-8%	-8%	+23%	-8%	-8%

2010 Technology	Operation Hours Per Year	Electricity Fraction (Portion of Electricity)	Total B/C Ratio	Emissions % Change, Relative to In-state, Average Central Generation Only: NOx	SOx	CO	CO_2	VOC	PM
Microturbine	599	7.7%	.6	+21%	+2%	+67%	+34%	+8%	-2%
Microturbine w/CHP	2,976	38.4%	.73	-28%	+2%	+100%	+12%	-29%	-21%
Diesel	599	7.7%	.63	+953%	+1,828%	+421%	+54%	+764%	+185%
ATS w/CHP	5,126	66.2%	.83	-75%	-8%	+293%	+16%	-40%	-38%
Gas Spark	599	7.7%	.6	+139%	-4%	+335%	+28%	+571%	+12%
Fuel Cell	2,976	38.4%	.57	-34%	-38%	-38%	+92%	-38%	-38%

Table 18. Change in Air Emissions for Distributed Generation Economic Run-hours, for Bill Analysis Using SDG&E/High Priced Tariff, 2002 and 2010

2002 Technology	Operation Hours Per Year	Electricity Fraction Portion of Electricity	Total B/C Ratio	Emissions % Change, Relative to In-state, Average Central Generation Only					
				NOx	SOx	CO	CO_2	VOC	PM
Microturbine	3,497	49.7%	1.09	+386%	+15%	+723%	+234%	+50%	-13%
Microturbine w/CHP	7,032	100.0%	1.26	+43%	+8%	+264%	+15%	-45%	-45%
Diesel	3,497	49.7%	1.07	+6,128%	+11,760%	+2,709%	+349%	+4,917%	+1,192%
ATS w/CHP	7,032	100.0%	1.41	-66%	-11%	+338%	+18%	-47%	-53%
Gas Spark	3,497	49.7%	1.10	+1,222%	-26%	+2,158%	+185%	+4,917%	+157%
Fuel Cell	3,497	49.7%	.57	-44%	-50%	-50%	+150%	-50%	-50%

2010 Technology	Operation Hours Per Year	Electricity Fraction Portion of Electricity	Total B/C Ratio	Emissions % Change, Relative to In-state, Average Central Generation Only					
				NOx	SOx	CO	CO_2	VOC	PM
Microturbine	3,497	49.7%	1.20	+136%	+11%	+433%	+220%	+50%	-15%
Microturbine w/CHP	7,032	100.0%	1.35	-35%	+4%	+140%	+16%	-43%	-47%
Diesel	3,497	49.7%	1.06	+6,128%	+11,760%	+2,709%	+349%	+4,917%	+1,192%
ATS w/CHP	7,032	100.0%	1.43	-83%	-11%	+338%	+18%	-47%	-53%
Gas Spark	3,497	49.7%	1.19	+895%	-26%	+2,158%	+178%	+3,675%	+74%
Fuel Cell	7,032	100.0%	1.07	-89%	-100%	-100%	+239%	-100%	-100%

7. Observations and Conclusions

Utility Perspective

Utility Peaking Distributed Generation

Economic Market Potential

As shown in Table 10, for load growth of 976 MW in 2002 even the least attractive distributed generation option evaluated (a microturbine) is less expensive than the utility grid option for about 29% of new load. Dual-fueled engines and small conventional combustion turbines are cost-effective for about 37% and 32% of load growth, respectively. Spark-gas engine gensets and the ATS are more cost-effective than the grid in about 54% and 58% of cases, respectively. Diesel engines are the most cost-effective: they have competitive cost in about 75% of situations.

In 2010 load growth is 1,144 MW. As shown in Table 11, economic market potential increases considerably for most distributed generators: dual fueled engines are now cost-effective for 52% of new load, conventional combustion turbines increase to 79%, ATSs improve to 70%, and microturbines increase to 75%. Spark-gas and Diesel engines hold steady at about 54% and 75%, respectively.

As discussed previously, utility-owned peaking units' cost-effectiveness is driven by their ability to provide electric capacity, when needed, at a cost that is lower than the utility's avoided cost for the grid solution. The results in Tables 10 and 11 indicate that, in many cases, distributed generators are able to meet that requirement.

Economic market potential estimates for peaking distributed generators tend not to be driven by variable operation cost because distributed generators have to operate for so few hours per year to yield cost-effective capacity benefits. This is especially true for Diesel engines, the distributed generator option with the lowest installed cost, highest variable cost and most significant emissions.

Therefore, the overall competitiveness of distributed generators for utility peak capacity applications is driven primarily by the fact that, in many cases, distributed generation alternatives have a low initial cost relative to many grid-based solutions involving central generation and "wires" (transmission and distribution) systems.

Virtually all cost-effective distributed generator deployment is at or near customers' loads, as opposed to being located at the utility distribution substation. These feeder locations are preferred because of the reliability benefit earned by distributed generators located near loads. It is important to note that many utilities do not allow "islanded" operation of distributed generators during grid outages; this type of operation would be necessary in order for a distributed generator to receive the reliability credit.

Beyond quantifiable benefits (avoided costs) distributed generators offer an increasingly important way for utilities to reduce risk associated with more permanent grid-based solutions in times of growing uncertainty in the utility marketplace.

Emissions

Peaking distributed generators, especially Diesel engines, produce greater amounts of emissions per unit of energy generated, compared to the existing mix of in-state generation. No peaking distributed generators have superior emissions relative to central in-state generation. But, because peaking distributed generators operate for so few hours per year, they do not emit as many air pollutants as baseload distributed generation when considered on a yearly basis.

Note again that California in-state central generation is dominated by facilities with limited or no air emissions: mostly nuclear and hydroelectric, but including some combustion turbines, geothermal and wind generation. However, when distributed generators are compared to the mix of all central generation serving California's demand for electricity, out-of-state and in-state, the net change in emissions due to distributed generation use would be somewhat less. This is because much of the electricity from out-of state is generated using coal.

Another important comparison for peaking distributed generators may be between distributed generators and the type of central station generation plant that would have to be used (or whose output would be purchased) if the distributed generator were not used. That additional central station capacity may be an existing plant that was not in use, for a variety of reasons; a refurbished or upgraded plant; or an entirely new plant.

If distributed generators are compared to the most likely type of new central power plant that would be used to upgrade existing facilities or to add new capacity, results would be different. When compared to an existing central-station peaking power plant (often an older or less efficient simple cycle combustion turbine based plant and with relatively high emissions per kWh), some distributed generators may be superior.

However, recent information from the California Energy Commission (CEC) suggests that the cumulative mix of new power plants (mainly using combustion turbines) and in-state generation is cleaner than the existing mix of in-state generation (as of 2000). If so, distributed generation could have greater incremental effects on emissions.

As an illustration, Figure 10 shows the resulting emissions if six options are pursued to meet new peak load demand growth. In one case a Diesel engine serves all new peak demand. In other cases ATS units with NO_x emission rates of 15 ppm, 5 ppm and 2.5 ppm are used for load growth according to their market potential, with in-state central generation serving the balance of new load. (As a reminder, 5 ppm was assumed for 2002 and 2.5 ppm for 2010; 15 ppm represents the worst case.) Another plot indicates total NO_x emissions if only the existing mix of in-state generation were used to meet new peak demand. Finally, a plot indicates NO_x emissions if new state-of-the-art natural gas fired combined-cycle central power plants meet all new load. Data for these new combined-cycle plants was obtained from the CEC from applications for operating permits. As can be seen from the graphs, the emissions impact of the Diesel engines is great, while the impact from the 15 ppm ATS is considerably less. The other options all result in emissions levels very close to that from central generation alone.

Expanding the scale of this graph results in Figure 11, from which it can be seen that the 5ppm ATS results in very slightly higher NO_x emissions than central generation alone, new combined-cycle plants result in slightly lower NO_x emissions, and the 2.5 ppm ATS in somewhat lower total NO_x.

As discussed previously, the market penetration of Diesel engines could be quite substantial in the next ten years, with a correspondingly substantial economic impact. However, that level of market penetration, if it occurred, would result in an increase of approximately 1,210 tons of NO_x in 2002 over the central-generation-only scenario, about 8%. In 2010, the mix of Diesels and central generation would add about 11,380 extra tons of NO_x, or about 63% higher than the expected NO_x levels if only central generation were to serve peak load growth.

On the other hand, market penetration of the Advanced Turbine System with NO_x emissions of 15 ppm would result in total NO_x emissions that are only slightly higher than those for central generation only (see Figure 11). Additionally, the Advanced Turbine System can be engineered in versions producing 2.5 to 5.0 ppm in the near term, with potential to go even lower over time.

Preliminary estimates suggest that a mix of central generation and new central station combined-cycle combustion turbines would reduce NO_x in 2002 by about 200 tons (1%), and in 2010 by about 1700 tons (more than 9%), compared to the central-generation-only case. Central generation plus the 2.5 ppm ATS would result in even lower values for NO_x.

Utility Baseload Distributed Generation

Economic Market Potential

For 2002 (results are shown in Table 12) the Advanced Turbine System (ATS) is the most attractive baseload distributed generator option: it is less expensive than the utility grid option for about 33% of the 976 MW load growth in that year. Small conventional combustion turbines could address 10% of new load cost-effectively while microturbines might be cost-effective for about 4% of new load. Fuel cells and engine-based solutions are not cost-effective.

For 2010 (see Table 13), the ATS is still the most attractive baseload distributed generation option, as it is economically competitive for 42% of the 1,144 MW load growth in that year. Combustion turbines meet about 16% of new load cost-effectively. Microturbines are less expensive than the utility grid option for about 14% of new load. Natural gas fueled PEM fuel cells are economically competitive for about 2% of load growth.

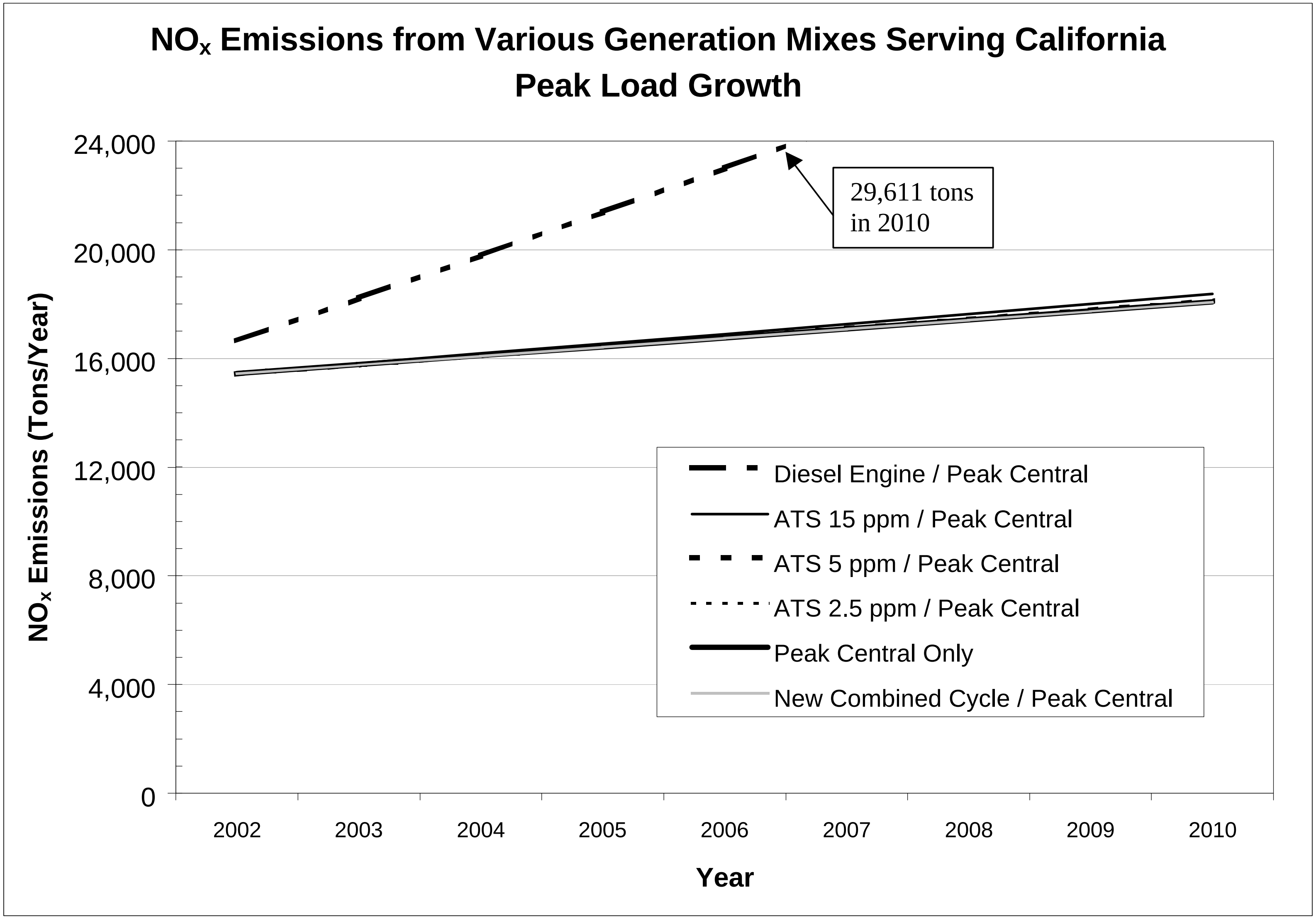

Figure 10. Total NO_x Emissions for Various Future Generation Mixes Serving All California Utility Peak Load Growth

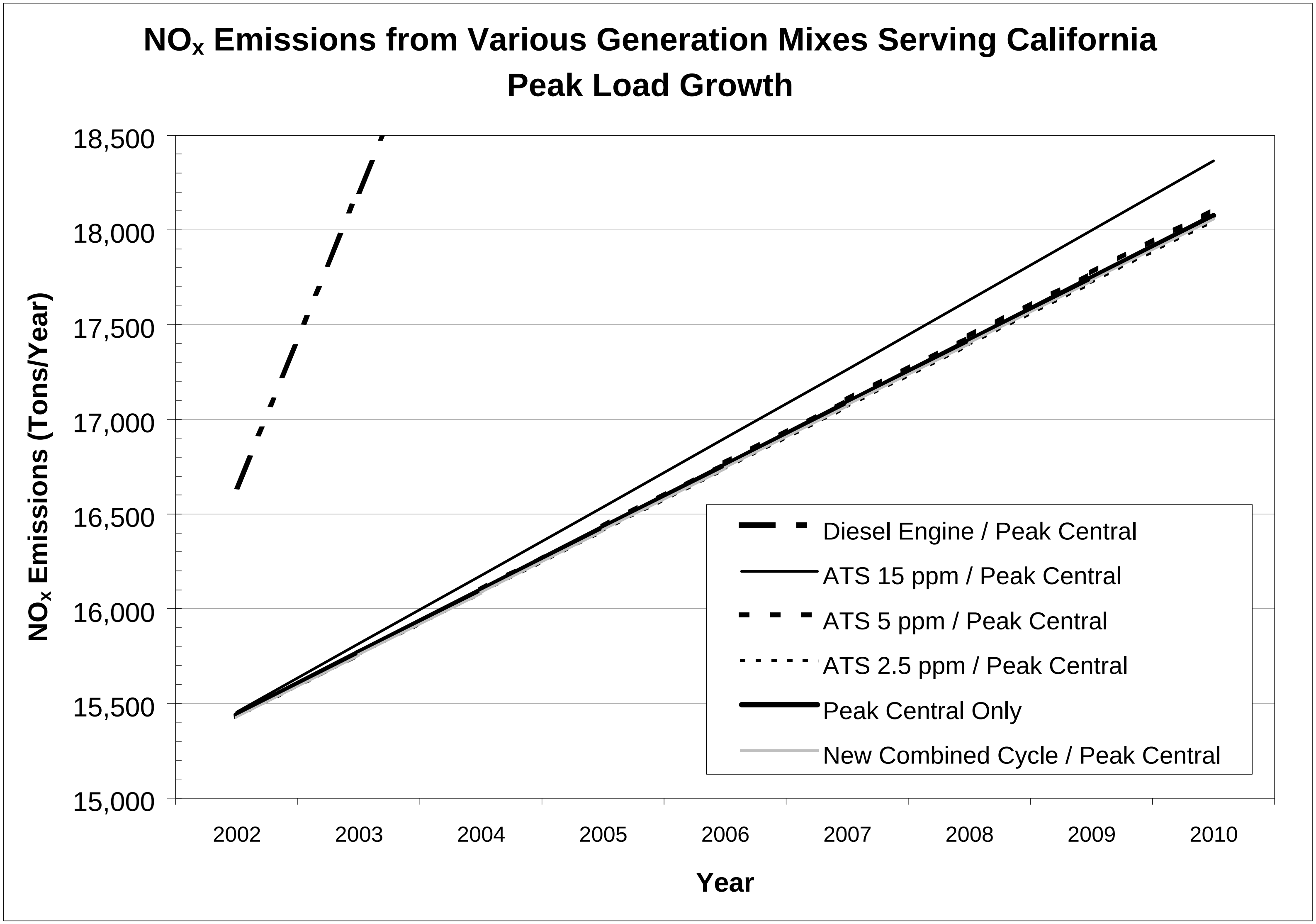

Figure 11. Total NO_x Emissions for Various Future Generation Mixes Serving All California Utility Peak Load Growth (enlarged scale)

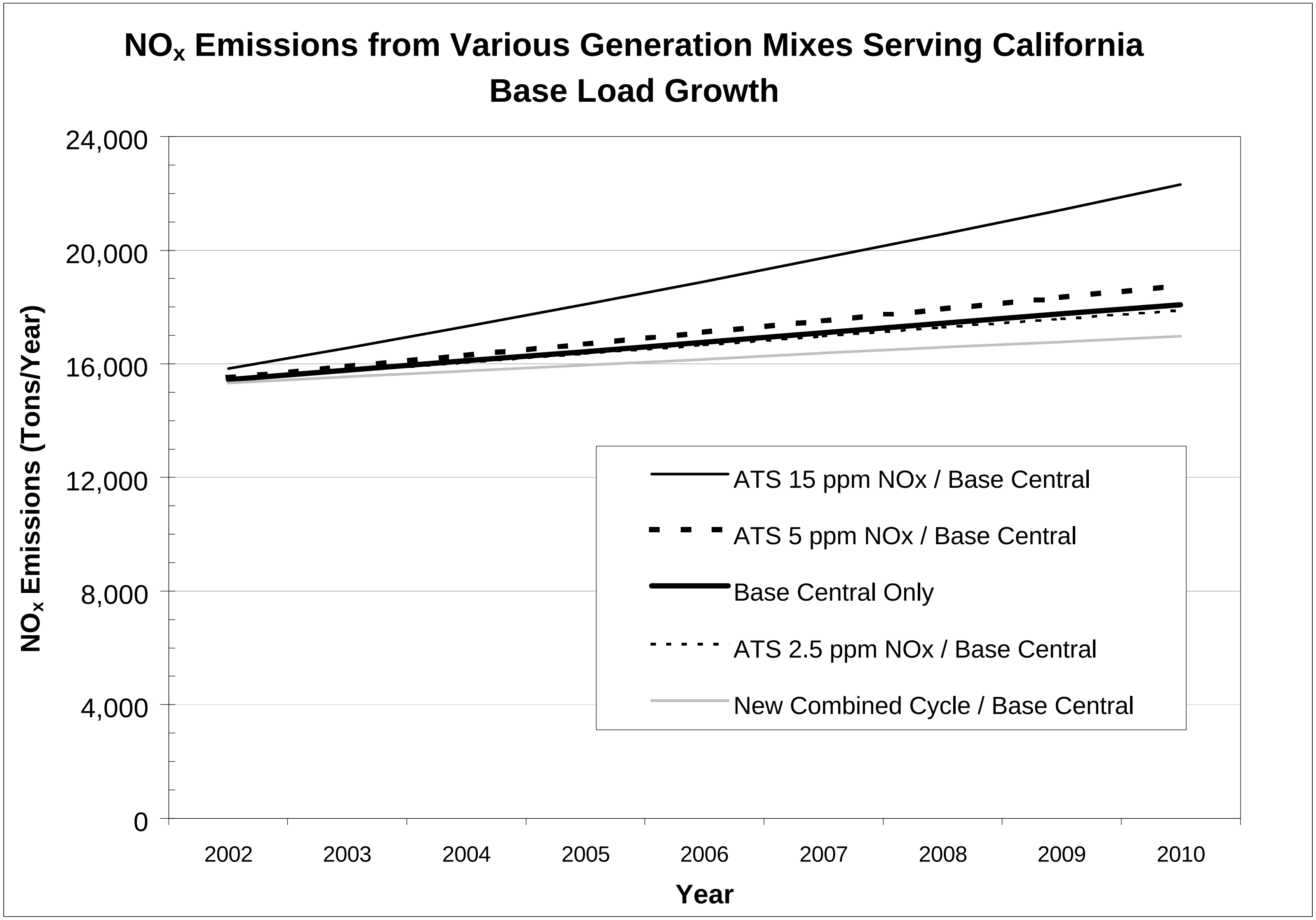

Figure 12. Total NO_x Emissions for Various Future Generation Mixes Serving Utility Base Load

The ATS seems to be unique as a baseload utility-owned distributed generation resource, primarily because of its superior efficiency and low cost. Conventional combustion turbines, though somewhat less efficient and more expensive than the ATS, may still be competitive for about 10% to 15% of new base load demand over the next ten years. Microturbines, due to their relatively low efficiency, are not quite cost-effective in 2002; as their efficiency improves and equipment costs are reduced, their market share should increase to about 14% by 2010.

Recall that for distributed generators to be cost-effective baseload resources for utilities, their total benefit usually must include both:

- **reduced/avoided** need and thus **cost for grid capacity** upgrades (i.e., fixed equipment cost)

  and

- **lower overall energy production** cost (i.e., variable operation cost), including fuel cost, over many hours per year. Unlike peaking distributed generators that must only operate for a few hundred hours per year to provide significant capacity credit, baseload distributed generators operate for many hours per year (4,774 hour/year for this evaluation).

Most cost-effective baseload distributed generation projects either involve CHP (feeder locations only) or are located at substation locations. The natural gas price is higher for distributed generators at feeder locations, so operation cost is higher. However, the higher priced gas means that the value of recaptured heat from CHP has relatively high value. Distributed generators at substation locations operate on lower priced city gate gas.

Overall, economic market estimates shown in Tables 12 and 13 indicate that baseload distributed generators have modest but growing potential to reduce overall electricity cost. In many circumstances, central grid electricity seems likely to be competitive with electricity from most types of distributed generators, possibly for the next decade. This is primarily due to two factors: 1) a maturing central generation fleet with relatively low financial carrying costs; and 2) low incremental production cost for electric energy from nuclear, hydro, fossil fuel and more modern and efficient combustion turbine-based power plants.

As with utility peaking distributed generators, beyond quantifiable benefits (avoided costs) baseload distributed generators may provide a means for utilities to reduce the risk associated with permanent grid-based solutions as deregulation takes hold in the electric utility marketplace. Electric service reliability enhancements are also possible with distributed generation.

Emissions

In most cases, relative to in-state central generation, emissions per unit of electric energy generated would be higher if baseload distributed generators are used in lieu of the grid.

Furthermore, because baseload distributed generators operate for so many hours annually, they would emit a higher amount of total air pollutants each year.

If 13% of new load were served by small combustion turbines, NO_x emissions increase nearly 250% over the grid-only option. Cost-effective microturbine installations meeting about 15% of the new demand would double NO_x emitted.

ATS is the exception. NO_x emissions would actually decrease slightly if cost-effective ATS deployment occurs in 2010 (given 42% economic market potential for the ATS and .00011 lbs/kWh from the ATS versus .00013 lbs/kWh for the current in-state central generation mix).

Therefore, except for the ATS and fuel cells, most baseload distributed generators have higher emissions relative to central in-state generation. In-state central generation is dominated by facilities with limited or no air emissions—mostly nuclear and hydroelectric with some geothermal and wind generation. As a result, it seems that cost-effective use of distributed generators for utility base load applications is likely to have a potentially economic impact with increased air emissions relative to existing in-state generation (though total emissions are likely to increase nominally given reasonable assumptions market penetration).

However, as noted elsewhere in this report, if most distributed generators are compared to the mix of all central generation used to generate electricity for use within California, from sources both within California and out-of-state, the net emissions impacts due to distributed generation use would be much less. This is because about 20% of the generation imported to California is generated using coal.

As an illustration, Figure 12 shows the resulting emissions if five different options are used to meet all new base load growth in California. In three cases, ATS units with 15, 5 and 2.5 ppm NO_x emissions, respectively, are added to the existing fleet of central in-state generation to meet load growth. A fourth plot indicates total emissions if new baseload is served by the existing mix of in-state generation. Finally, a fifth plot indicates NO_x emissions if new state-of-the-art central combined cycle power plants meet all baseload demand growth.

Fuel cells are superior to all other distributed generators with regard to emissions. But installed cost for fuel cells is and will continue to be too high for them to claim a significant economic market potential for at least the next four to six years. In the long term, ongoing research and development efforts are expected to reduce fuel cell costs.

Customer Perspective

Based on the results shown in Table 16, for tariffs in effect for most of the state, distributed generators are not cost-effective. For expected electric utility prices that apply to at least 80% of the state, the best total benefit/cost values were only about 0.9, and the distributed generators that were able to achieve that figure did so only because they were operated in CHP mode. Furthermore, only distributed generators with CHP had a net incremental electricity production cost (net of avoided boiler fuel cost) that was low enough to justify more than a few hundred hours of operation.

Total B/C for engines, operated mostly for peak-load reduction, are somewhat lower than those for distributed generators with CHP, at about 0.65. Natural gas and Diesel engines are the most attractive for peak shaving due to competitive lower equipment cost and reasonable fuel efficiency. Microturbines have total B/C ratios that are still lower, between 0.5 and 0.6. Fuel cells just come into their own if higher electric prices prevail, and when expected fuel efficiency and installed cost are achieved.

For regions of the state where higher electricity prices prevail, distributed generators may be cost-effective for operation during several thousand hours per year. For example, even the relatively inefficient microturbine and expensive to operate Diesel engine could operate for more than 3,400 hours if higher electricity prices prevail.

One important potential exception is worth noting. Figure 13 shows the effect of installed cost on the overall benefit/cost relationship for customer-owned Diesel engines. The engines operate for the number of hours specified in the legend, primarily so utility customers avoid demand charges and purchase of expensive on-peak electric energy. The importance of this chart is that it illustrates the potential for dramatic air emission impacts if customers interconnect existing back-up Diesel generators to serve as “peak shavers.” Existing generators can be retrofitted for as little as $50/kW.

Electric utility customers will tend to use distributed generators primarily to avoid peak demand charges, and also to avoid high electric energy prices during on-peak price periods. Only if a distributed generator is very fuel-efficient, or if CHP is employed, will customer-owned distributed generators tend to operate enough to serve all the customer’s electricity needs for the entire year (i.e., few distributed generators can compete with the grid for off-peak electric energy).

Because of deregulation and competition, utilities have unbundled the price for electricity into fixed and variable components, e.g., for generation, transmission, and distribution equipment (fixed costs) and the cost for fuel (variable costs). Electric energy is a variable cost and is priced according to the time that it used, because the cost to produce electricity varies throughout the year. This is referred to as time-of-use (TOU) pricing. Fixed costs associated with utility generation, transmission and distribution equipment for capacity upgrades are reflected as separate components of utility price, i.e., demand charges. These charges may also be time-specific.

At the same time, new distributed generators and vendors offer a growing array of options to utility customers who have become willing to consider alternatives to grid electricity.

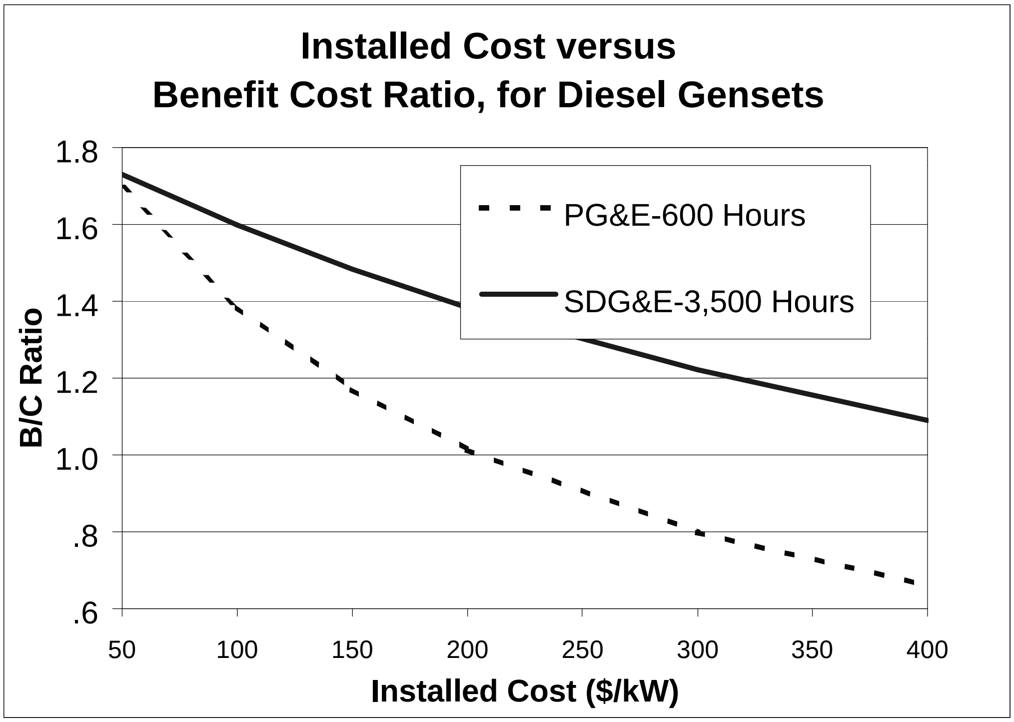

Figure 13. Diesel Engine Distributed Generator B/C versus New Equipment or Retrofit Cost

Beyond direct cost reduction, another driver of customer use of peaking distributed generators is improvement of service reliability. Some utility customers may install distributed generators to improve the reliability of their electric service beyond levels of reliability that a utility can or will offer. That may be the most compelling reason for specific customers to install peaking distributed generators. If reliability-related benefits are coupled with a credit for peak electric demand reduction (from the utility), then distributed generators may be quite attractive.

The authors believe that the bill analysis results presented here for PG&E and for SDG&E tariffs bracket the theoretical potential. Some larger municipal utilities serving the areas of interest have somewhat higher prices than PG&E, though SDG&E's prices are probably indicative of municipal utilities with higher prices.

Distributed Generator Emissions

As would be expected, because emissions from the various distributed generator technologies differ greatly (as do their costs), the environmental impacts of distributed generation also diverge.

When comparing combustion-based distributed generators to the mix of in-state generation, all have moderate to significant air quality impacts, especially with regard to all emissions except SO_x. However, some distributed generators are nearly as clean as, or even cleaner than, *new* central generation.

Gas-spark and dual fueled engine generators, though economically viable for situations requiring shorter run-times, do produce higher NO_x emissions than in-state generation. Therefore, in regions with central generation that emits relatively little NO_x and with high cost electricity (and thus high price), gas fueled engines may indeed be cost-effective but will result in an increase in NO_x, CO, CO_2 and particulate emissions. Research and development continues in this area and steady progress is expected with regard to NO_x and CO emissions.

Microturbines without CHP seem best suited to applications where annual run times are low. Though projected to be inexpensive to purchase and install, they are not especially fuel-efficient and thus have relatively high operating costs. CO_2 emissions are higher than those of other distributed generators except Diesel engines.

In addition, combustion turbines can emit significant amounts of CO and NO_x, especially when compared to existing in-state generation. Progress is being made to reduce these emissions, especially NO_x. Unless forbidden by air emission regulations lower cost peaking units seem destined to emit 25 ppm NO_x or less and microturbine advocates have targets of 10 ppm or less (perhaps much less) for systems used for baseload operation and/or located within in air quality non-attainment areas.

Based on the study's results, the ATS seems to combine key features needed for a superior distributed generator solution: competitive installed cost; proven, well understood concepts and design approaches; and fuel-efficient and reliable operation with relatively low NO_x emissions.

Fuel cells show great promise because their air emissions are so much lower than those from combustion-based distributed generators and central station generation—even if fueled by natural gas. Fuel cells' emissions are inherently lower because of the fuel-to-electricity-conversion process used, and they have a fuel *efficiency* advantage over all but the best central generators. CHP for fuel cells would have a somewhat less dramatic effect on economic competitiveness than for ATS because, in general, less heat can be recouped from fuel cell operation than from turbines.

CHP increases the economic viability of distributed generator projects significantly. CHP also has an important, often significant incremental impact on air emissions (relative to generation-only projects).

Other Observations

Economic market potential estimates are just that: potential. In actuality, adoption of distributed generation, even though cost-effective, will only ramp up slowly, based on a wide range of factors such as unfamiliarity with the technologies, most energy users' lack of sophistication regarding energy costs and technology to make the make-or-buy decision, the reluctance of regulators to allow "wires" utilities to own and operate distributed generators, local air regulations, etc. A separate evaluation is required to estimate the rate of adoption.

Changes in air emissions associated with cost-effective use of distributed generation in this study were based on a mix of central generation that is not sustainable. No additional hydroelectric resources are available, no new nuclear plants will be built, and other renewable technologies, while their growth is increasing, will not be significant sources of new capacity for the foreseeable future. Most new central generation will be gas fueled combustion turbine based.

So it is important to consider how results in this study would be different if distributed generators were compared to the "next" source of generation capacity used to meet new load. If distributed generators are assumed to compete against the most likely type of new central power plant that would be added to meet new load, then they will have a lower incremental effect on total air emissions. If distributed generators are compared to existing, older, inefficient combustion turbines with relatively high emissions (per kWh), then some distributed generators may have superior emissions.

Regional Implications for Air Emissions

Up to this point in the report, no consideration was given to the geographic location of distributed generators. To allocate distributed generator deployment (and therefore emissions) among California air districts, county-by-county economic and population data were used to estimate how much energy use occurs in each county [21]. Then air management districts were reconciled with county data to calculate a "load intensity factor" for each air district [22]. Load intensity factor is based on key county-by-county population, sales, and income.

Next, based on the market share estimates for utilities and the economic run hours for customers previously calculated, NO_X emissions are allocated to the eight air districts of interest. Note that, based on the calculated load intensity factors, those air districts represent about 89% of the state's entire load. Table 19 summarizes the study assumptions that are relevant here.

Table 19. Inputs for Emissions Allocation

Year	2002
Load (GW)	65.3
Load Growth Rate (%/yr)	2.0
Load Growth (MW)	976
Peak Hours per Year	200
Base Load Hours per Year	4,774
Emission Type	NO_x
Central Emission Factor (lb/kWh)	.00013
Industrial Segment Portion of Total	.20

Tables 21 and 22 show air district-specific emissions results for the utility peak load and base load situations, respectively. Tables 22 and 23 show results for the customer low and high priced electricity situations, respectively.

Table 20. Air-District-Specific Change in NO_x Emissions, Utility, Peak Load, 2002

DG Name	Microturbine	ATS	Conventional CT	Dual Fueled Engine	Otto/Spark Engine	Diesel Engine
Economic Run Hours	28.7%	57.7%	32.1%	36.8%	54.1%	75.5%
NOx Emission Factor (lbs/kWh)*	.0012	.00021	.00124	.0100	.0032	.0170

*Up to 15% utility DG is CHP. Microturbine Net: .0005 lbs/kWh, ATS Net: -0.00028 lbs/kWh.

Change in total Utility Peak Load NOx Emissions (tons)

Air District	Microturbine	ATS	Conventional CT	Dual Fueled Engine	Otto/Spark Engine	Diesel Engine
Bay Area AQMD	+6.9	+1.1	+8.	+82.	+37.5	+287.7
Mojave Desert AQMD	+1.2	+0.2	+1.4	+14.3	+6.6	+50.3
Monterey Bay Unified APCD	+0.6	+0.1	+0.7	+7.	+3.2	+24.4
Sacramento Metro AQMD	+1.1	+0.2	+1.2	+12.5	+5.7	+43.9
San Diego County APCD	+2.5	+0.4	+2.9	+29.4	+13.4	+103.1
San Joaquin Valley Unified APCD	+2.1	+0.3	+2.5	+25.2	+11.5	+88.3
Santa Barbara County APCD	+0.4	+0.1	+0.4	+4.3	+2.	+15.
South Coast AQMD	+11.8	+1.8	+13.7	+139.7	+63.9	+490.
Selected Air Districts	+26.6	+4.	+30.8	+314.4	+143.8	+1,102.6
All Air Districts	+30.	+4.5	+34.8	+354.5	+162.1	+1,243.1

Table 21. Air-District-Specific Change in NO_x Emissions, Utility, Base Load, 2002

DG Name	Microturbine	ATS	Conventional CT	Dual Fuel Engine	Fuel Cell--PEM, Gas	Fuel Cell--PhosAcid,
Economic Run Hours	4.4%	32.9%	10.4%	0.1%	0.0%	0.0%
NOx Emission Factor (lbs/kWh)*	.0012	.00021	.00124	.0100	.000015	.000015

*Up to 15% utility DG is CHP. Microturbine Net: .0005 lbs/kWh, ATS Net: -0.00028 lbs/kWh.

Change in total Utility Base Load NOx Emissions (tons)

Air District	Microturbine	ATS	Conventional CT	Dual Fuel Engine	Fuel Cell--PEM, Gas	Fuel Cell--PhosAcid,
Bay Area AQMD	+25.4	+14.3	+62.2	+5.3	-0.	-0.
Mojave Desert AQMD	+4.4	+2.5	+10.9	+0.9	-0.	-0.
Monterey Bay Unified APCD	+2.2	+1.2	+5.3	+0.5	-0.	-0.
Sacramento Metro AQMD	+3.9	+2.2	+9.5	+0.8	-0.	-0.
San Diego County APCD	+9.1	+5.1	+22.3	+1.9	-0.	-0.
San Joaquin Valley Unified APCD	+7.8	+4.4	+19.1	+1.6	-0.	-0.
Santa Barbara County APCD	+1.3	+0.7	+3.2	+0.3	-0.	-0.
South Coast AQMD	+43.2	+24.4	+106.	+9.1	-0.	-0.
Selected Air Districts	+97.3	+54.8	+238.5	+20.4	-0.	-0.
All Air Districts	+109.7	+61.8	+268.9	+23.	-0.	-0.

Table 22. Air-District-Specific Change in NO_x Emissions, Customer, Low Priced Electricity, 2002

DG Name	Microturbine	Micro turbine w/CHP	Diesel	ATS w/CHP	Gas Spark	Fuel Cell
Economic Run Hours	599	2,791	599	4,807	599	599
NOx Emission Factor (lbs/kWh)*	.0012	.0005	.0170	-.00028	.0035	.00002

*Net for CHP. Microturbine generator: .0012 lbs/kWh, ATS generator: .0002106 lbs/kWh.

Change in Total NOx Emissions (tons)

Air District	Microturbine	Micro turbine w/CHP	Diesel	ATS w/CHP	Gas Spark	Fuel Cell
Bay Area AQMD	+695.5	+1,116.6	+10,966.1	-2,143.5	+2,190.6	-74.8
Mojave Desert AQMD	+121.6	+195.1	+1,916.6	-374.6	+382.9	-13.1
Monterey Bay Unified APCD	+58.9	+94.6	+929.4	-181.7	+185.7	-6.3
Sacramento Metro AQMD	+106.2	+170.5	+1,674.9	-327.4	+334.6	-11.4
San Diego County APCD	+249.2	+400.	+3,928.8	-767.9	+784.8	-26.8
San Joaquin Valley Unified APCD	+213.5	+342.7	+3,365.5	-657.8	+672.3	-22.9
Santa Barbara County APCD	+36.2	+58.1	+570.5	-111.5	+114.	-3.9
South Coast AQMD	+1,184.6	+1,901.7	+18,677.2	-3,650.7	+3,731.	-127.3
Selected Air Districts	+2,665.7	+4,279.4	+42,029.	-8,215.1	+8,395.8	-286.5
All Air Districts	+3,005.5	+4,824.7	+47,385.1	-9,262.	+9,465.8	-323.

*Assuming that industrial/large institutional customers' load is 20.% of total load.

Table 23. Air-District-Specific Change in NO_x Emissions, Customer, High Priced Electricity, 2002

DG Name	Microturbine	Micro turbine w/CHP	Diesel	ATS w/CHP	Gas Spark	Fuel Cell
Economic Run Hours	3,497	7,032	1,904	7,032	3,497	3,497
NOx Emission Factor (lbs/kWh)*	.0012	.0005	.0170	-.00028	.0035	.00002

*Net for CHP. Microturbine generator: .0012 lbs/kWh, ATS generator: .0002106 lbs/kWh.

Change in Total NOx Emissions (tons)

Air District	Microturbine	Micro turbine w/CHP	Diesel	ATS w/CHP	Gas Spark	Fuel Cell
Bay Area AQMD	+4,061.1	+2,813.7	+34,865.	-3,136.	+12,790.6	-436.5
Mojave Desert AQMD	+709.8	+491.8	+6,093.4	-548.1	+2,235.4	-76.3
Monterey Bay Unified APCD	+344.2	+238.5	+2,954.9	-265.8	+1,084.	-37.
Sacramento Metro AQMD	+620.3	+429.7	+5,324.9	-479.	+1,953.5	-66.7
San Diego County APCD	+1,455.	+1,008.1	+12,491.1	-1,123.5	+4,582.5	-156.4
San Joaquin Valley Unified APCD	+1,246.4	+863.5	+10,700.	-962.4	+3,925.4	-134.
Santa Barbara County APCD	+211.3	+146.4	+1,813.7	-163.1	+665.4	-22.7
South Coast AQMD	+6,916.8	+4,792.2	+59,381.1	-5,341.1	+21,784.6	-743.4
Selected Air Districts	+15,564.7	+10,783.8	+133,624.1	-12,019.1	+49,021.5	-1,672.8
All Air Districts	+17,548.2	+12,158.1	+150,653.	-13,550.7	+55,268.8	-1,886.

*Assuming that industrial/large institutional customers' load is 20.% of total load.

Next Steps and R&D Needs

Since the original intent of this study was to examine the distributed generation emissions "from 30,000 feet," and because the distributed generation technologies and market factors are evolving rapidly, many aspects of this analysis seem worthy of further study or refinement. A few such issues are described below.

Perhaps the most important next step might be to broaden the customer segments to include commercial or even residential sectors, since the price paid for electricity directly determines the customer market penetration. The industrial customer rates used herein were very low compared to those of commercial or residential customers; even the proposed industrial rates used in this study have since been revised.

Distributed generation technology continues to advance and market applications expand. Microturbines have been developed whose size matches commercial customers very well and whose emissions are promising. Recent residential fuel cell technology announcements may accelerate their market entry, either for individual residences, multiple residence buildings or in microgrids. Power quality issues and reliability for critical loads may add value to distributed generation installations and hence accelerate market entry.

Some real-world market factors may now be ready for inclusion or refinement, such as exit fees, standby charges or interconnection costs for customer owned distributed generation; similarly the real availability of natural gas to candidate sites, costs for gas connection, and firmness of service may warrant further analysis.

Another emerging market niche is the activation of standby generators, especially for temporary service to help utilities get through summer peaks. While these markets were addressed in a cursory manner, the real costs of activation, conversion of Diesel units to natural gas (full or partial conversion), implications of the advent of cleaner reciprocating engines, and the expected hours of operation in such service were not fully analyzed.

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9. Glossary of Terms, Abbreviations and Symbols

AC – alternating current
APCD – air pollution control district
AQMD – air quality management district
ATS – Advanced Turbine System
BACT – best available control technology
BARCT – best available retrofit control technology
B/C – benefit-cost ratio
bhp – brake horsepower (1 bhp = 746 Watts)
Btu – British thermal unit
CARB – California Air Resources Board
CC – combined cycle
CEC – California Energy Commission
CHP – combined heat and power (cogeneration)
CO – carbon monoxide
CO_2 – carbon dioxide
CT – combustion turbine
D – distribution
DC – direct current
DER – distributed energy resources
DG – distributed generation
DR – distributed resources
DSM – demand-side management
DUVal – Distributed Utility Valuation model (utility)
DUVal-C – Distributed Utility Valuation model (customer)
EPA– Environmental Protection Agency
ESP – electric service provider
FERC – Federal Energy Regulatory Commission
g – gram
G – generation, central-station
GW – gigaWatt(s)
HHV – high heat value (before considering losses)
IC – internal combustion
kW – kilowatt(s)
kWh – kilowatt-hour(s)
lb – pound(s)
LHV – low heat value (net after losses)
MMBtu – million Btu
MW – megawatt(s)
NG – natural gas
NO_x – oxides of nitrogen
O&M – operation and maintenance (costs)
PCU – power conditioning unit
PEM – proton exchange membrane (fuel cell)
PM – particulate matter
ppm – parts per million
PV – photovoltaic(s)
SCF – standard cubic foot
SO_x – oxides of sulfur
T – transmission
T&D – transmission and distribution
TOU – time of use (pricing)
UDC – utility distribution company
UHC – unburned hydrocarbons
VOC – volatile organic compounds
Watt – unit of power

Appendix A. Utility Operational and Avoided Cost Assumptions

Peak Load Hours

For this study peak demand hours are defined as a typical summer peaking utility's highest 200 load hours. The significance is that a distributed generator is assumed to provide "peaking service" if it can generate during those 200 hours.

System Load Factor and Annual Load Hours

The annual average load factor is assumed to be 0.545. Annual full load equivalent hours (or full load hours) is 0.545 * 8760 hour per year = 4,774 annual load hours.

Generation Capacity Cost

Generation capacity avoided costs assumed for the analysis are shown in Table A-1. The peaking resources reflect a range of costs from refurbishment/repowering of an existing peaker to purchase of low cost, inefficient additional combustion turbines, possibly used equipment, to be used for peaking only. The baseload capacity values reflect a range of new power plants: combustion turbine based combined cycle plants and new boiler-based power plants. A triangular probability distribution for these costs is assumed.

Transmission and Distribution Capacity Cost

Based on proprietary information used by DUA, an average of $18.03/kW-year cost was assumed for distribution capacity needed to serve new electric load. $5.97/kW-year is assumed as the average cost for transmission capacity needed to serve new load. Also based on information proprietary to DUA, a statistical distribution is developed for these costs. These are mean values; actual values vary from location to location. DUA uses a statistical representation of that variation.

Gen. Capacity *Avoided Cost*			
1.a. *Base Load*			
FYI @ .115 FCR		Low	70.0
$500/kW => $57.5/kW-yr	Triangular Distribution	Mean	80.0
$800/kW => $92/kW-yr		High	90.0
1.b. *Peaking*			
FYI @ .115 FCR		Low	20.0
$200/kW => $23/kW-yr	Triangular Distribution	Mean	30.0
$400/kW => $46/kW-yr		High	35.0

Table A-1: Baseload and Peaking Generation Capacity Costs ($/kW-yr)

Electric Energy Cost

The assumed average utility marginal cost for electric energy during peak load hours is 4¢/kWh while annual average or baseload energy costs are assumed to be 2.5¢/kWh. These values were developed from the forecasted energy costs in the California investor-owned utility tariffs for 1999 that were used in this study (Appendix B).

Line Losses

When transmitting electric energy through utility transmission and distribution (T&D) systems the resistivity of wires and transformers leads to losses. These resistive or "I^2R" losses are assumed to be 4% on average throughout the year. In essence this means that to receive 1 kWh at the load requires generation of approximately 1.042 kWh upstream to make up for T&D-related energy losses (1.042 times .96 equals 1.0).

Furthermore, losses are assumed to be higher during peak load hours, affecting "capacity losses" (or reduced ability to carry current). A 6% reduction in load carrying capability is assumed. That means that to get 1 kW of power to the customer during peak demand periods requires about 1.064 kW of generation capacity.

Reliability Benefits Associated with Distributed Generation Use

The value of unserved energy (or value of service) and the total number of hours during the year that a customer cannot be served is a measure of the customers' "cost" of reliability." To the extent that this cost can be avoided by use of a distributed generator, that savings is a benefit that is assumed to accrue to the utility. The U.S. average value of service is assumed to be $3 per kWh "not served," and there are 2.5 hours per year of outages. Therefore, the reliability benefit from use of distributed generators is estimated to be $3 * 2.5 hours = $7.5 per kW-yr. of load [23].

It is important to note that many utilities do not allow "islanded" operation of distributed generators during grid outages; this type of operation would be required in order for a given distributed generator to receive the reliability credit. Such isolated operation of a distributed generator requires a sophisticated interconnection scheme that protects the utility grid, its customers, and the load served by the distributed generator during transitions from grid to distributed generator power and vice versa.

Appendix B. Tariff Summaries, Customer Demand and Energy Use

Electric Utility Tariffs

Utility: PG&E
Tariff: E20--Proposed
Service: > 500 kW, Secondary Voltage
Cost: 3.9 ¢/kWh or 272.0 $/kW-yr

Energy Supply	¢/kWh	$/kW-yr	Energy/ Total
Energy/Variable Only	2.93	205.3	
Total	2.93	205.3	1.00

Supply Cost/Total Cost Ratio 75.5%

Season	Period	Days and Times	Annual Total Hours in Period "Bin"	Load Factor (% of Peak)	Annual Load Hours in Period "Bin"	Period Peak Demand/ Annual Peak Demand	Energy Supply Energy Price (¢/kWh)	Energy Supply Annual Cost ($/kW-yr)	Energy Supply Demand Charge ($/kW-mo)	Energy Supply Demand Cost ($/kW-yr)
Summer May - Oct	Peak	12:00 P.M. - 5:00 P.M Weekdays.	764	.95	726	1.00	4.77	34.6	0.0	0.0
Months (#) 6	Mid-Peak	8:30 A.M. - 12:00 P.M., 6:00 P.M. - 9:30 P.M. Weekdays	891	.85	758		3.38	25.6	0.0	0.0
	Off-Peak	9:30 P.M. - 8:30 A.M. Weekdays, All Hours Weekends and Holidays	2,724	.75	2,043		2.25	45.9	0.0	0.0
Winter Nov -Apr	Peak	N/A	0	.00	0	1.00		0.0	0.0	0.0
Months (#) 6	Mid-Peak	8:30 A.M. - 9:30 P.M. Weekdays	1,656	.88	1,449		3.25	47.0	0.0	0.0
	Off-Peak	9:30 P.M. - 8:30 A.M. Weekdays, All Hours Weekends and Holidays	2,724	.75	2,043		2.55	52.2	0.0	0.0
		Totals	8,760	.801	7,019	--	2.93	205.3	0.0	0.0
						Annual, 8760 hours basis	2.87			

Notes 1. Present E20 Rate effective April 21, 1999.
2. Price for service at higher voltage and/or for non-firm service are somewhat lower.

Utility: PG&E
Tariff: E20--Pr
Service: > 500 kW
Cost: 3.9 ¢/kV

T&D	¢/kWh	$/kW-yr	Variable/ Total
Variable Only	0.00	0.0	
Total	0.95	66.7	.00

T&D Cost/Total Cost Ratio 24.5%

Season	*Period*	T&D Variable Charge (¢/kWh)	T&D Variable Cost ($/kW-yr)	T&D Demand Charge ($/kW-mo)	T&D Demand Cost ($/kW-yr)	***Bill*** ***(¢/kWh)***	***Total**** ***($/kW-yr)***
Summer May - Oct	Peak	0.00	0.0	9.05	54.3	12.25	88.9
Months (#) 6	Mid-Peak	0.00	0.0	0.00	0.0	3.38	25.6
	Off-Peak	0.00	0.0	0.00	0.0	2.25	45.9
Winter Nov -Apr	Peak		0.0	2.06	12.4		12.4
Months (#) 6	Mid-Peak	0.00	0.0	0.00	0.0	3.25	47.0
	Off-Peak	0.00	0.0	0.00	0.0	2.55	52.2
		0.0	0.0	5.6	66.7	3.87	**272.0**

* Both values include energy/variable and demand charges, for supply and T&D

Utility: SCE

Tariff: TOU-8-RTP--Proposed

Service: > 500 kW, Secondary Voltage

Cost: 5.01 ¢/kWh or 350.7 $/kW-yr

Energy Supply Totals

	¢/kWh	$/kW-yr	Variable/ Total
Energy/Variable Only	2.499	175.1	
Total	2.499	175.1	100.0%

Supply Cost/Total Cost Ratio 49.9%

Time Periods			Customer Load				Energy Supply			
Season	*Period*	*Days and Times*	*Annual Total Hours in Period "Bin"*	*Load Factor (% of Peak)*	*Annual Load Hours in Period "Bin"*	*Period Peak Demand / Annual Peak Demand*	Energy Supply Variable Price *(¢/kWh)*	Energy Supply Variable Cost *($/kW-yr)*	Energy Supply Capacity Charge *($/kW-mo)*	Energy Supply Capacity Cost *($/kW-yr)*
Summer Jun - Sept	Peak	12:00 P.M. - 5:00 P.M Weekdays.	503	.95	478	1.00	6.00	28.7	0.0	0.0
Months (#) 4	Mid-Peak	8:30 A.M. - 12:00 P.M., 6:00 P.M. - 9:30 P.M. Weekdays	587	.85	499	.90	4.00	20.0	0.0	0.0
	Off-Peak	9:30 P.M. - 8:30 A.M. Weekdays, All Hours Weekends and Holidays	1,829	.80	1,463	.80	2.80	41.0	0.0	0.0
Winter Oct - May	Peak	N/A	0		-			-		-
Months (#) 8	Mid-Peak	8:30 A.M. - 9:30 P.M. Weekdays	2,221	.85	1,887	.90	2.40	45.3	0.0	0.0
	Off-Peak	9:30 P.M. - 8:30 A.M. Weekdays, All Hours Weekends and Holidays	3,619	.74	2,678	.70	1.50	40.2	0.0	0.0
		Totals	8,760	.800	7,007	.802	2.499	175.1	0.0	0.0
					Annual, 8760 hours basis		2.43			

Utility: SCE
Tariff: TOU-8-RTP--Proposed
Service: > 500 kW, Secondary Voltage
Cost: 5.01 ¢/kWh or 350.7 $/kW-yr

Delivery Services Totals

	¢/kWh	$/kW-yr	Variable/ Total
Variable Only	1.105	77.4	
Total	2.506	175.6	44.1%

Delivery Cost/Total Cost Ratio 50.1%

Time Periods			Delivery Services					Bin Peak? FALSE	Bill Total**	
Season	Period	Days and Times	Delivery Variable Charge (¢/kWh)	Delivery Variable Cost ($/kW-yr)	Delivery Demand Charge ($/kW-mo)	Delivery Demand Cost ($/kW-yr)	Delivery Monthly Charge* ($/kW-mo)	Delivery Monthly Cost * ($/kW-yr)	(¢/kWh)	($/kW-yr)
Summer Jun - Sept	Peak	12:00 P.M. - 5:00 P.M Weekdays.	1.968	9.4	7.53 $\boxed{4.08 + 3.45}$	30.1	3.00	12.0	16.77	80.2
Months (#) 4	Mid-Peak	8:30 A.M. - 12:00 P.M., 6:00 P.M. - 9:30 P.M. Weekdays	1.133	5.7	0.74	2.7	0.00	0.0	5.67	28.3
	Off-Peak	9:30 P.M. - 8:30 A.M. Weekdays, All Hours Weekends and Holidays	.723	10.6	0.00	0.0	0.00	0.0	3.52	51.6
Winter Oct - May	Peak	N/A		-		-		-	-	-
Months (#) 8	Mid-Peak	8:30 A.M. - 9:30 P.M. Weekdays	1.684	31.8	4.08	29.4	3.00	24.0	6.91	130.5
	Off-Peak	9:30 P.M. - 8:30 A.M. Weekdays, All Hours Weekends and Holidays	.747	20.0	0.00	0.0	0.00	0.0	2.25	60.2
		Totals	1.105	77.4	5.2	62.2	3.0	36.0	5.01	**350.7**

* "Grid Charge"
This is a monthly charge based on highest monthly peak load over 12 months.

** Equivalent values expressed in different units.
Total Cost =
supply cost + delivery cost.

Utility: SDG&E

Tariff: A6 TOU

Service: > 500 kW, Primary Voltage

Cost: 6.77 ¢/kWh or 479.0 $/kW-yr

Energy Supply Totals

	¢/kWh	$/kW-yr	Variable/ Total
Energy/Variable Only	2.517	178.1	
Total	2.517	178.1	100.0%

Supply Cost/Total Cost Ratio 37.2%

Time Periods			Customer Load						Energy Supply			
Season	Period	Days and Times	Annual Total Hours in Period "Bin"	Monthly Load Hours	Load Factor (% of Peak)	Annual Load Hours in Period "Bin"	Monthly Load Hours	Period Peak Demand / Annual Peak Demand	Energy Supply Variable Price (¢/kWh)	Energy Supply Variable Cost ($/kW-yr)	Energy Supply Capacity Charge ($/kW-mo)	Energy Supply Capacity Cost ($/kW-yr)
Summer May - Sept	Peak	11:00 A.M. - 6:00 P.M Weekdays.	739	148	.95	702	140	1.00	5.50	38.6	0.0	0.0
Months (#) 5	Mid-Peak	6:00 A.M. - 11:00 A.M., 6:00 P.M. - 10:00 P.M. Weekdays	951	190	.85	808	162	.90	4.50	36.4	0.0	0.0
	Off-Peak	10:00 P.M. - 6:00 A.M. Weekdays, All Hours Weekends and Holidays	1,960	392	.75	1,470	294	.80	2.00	29.4	0.0	0.0
Winter Oct - Apr	Peak	5:00 P.M. - 8:00 P.M Weekdays.	447	63.9	.90	402.5	57.5	.90	2.50	10.1	0.0	-
Months (#) 7	Mid-Peak	6:00 A.M. - 5:00 P.M., 8:00 P.M. - 10:00 P.M Weekdays	1,938	277	.85	1,647	235	.85	2.00	32.9	0.0	0.0
	Off-Peak	10:00 P.M. - 6:00 A.M. Weekdays, All Hours Weekends and Holidays	2,725	389	.75	2,043	292	.80	1.50	30.7	0.0	0.0
		Annual	8,760	730	.808	7,074	589	.844	2.517	178.1	0.0	0.0
								Annual, 8760 hours basis	2.44			

Utility: SDG&E
Tariff: A6 TOU
Service: > 500 kW, Primary Voltage
Cost: 6.77 ¢/kWh or 479.0 $/kW-yr

Delivery Services Totals

	¢/kWh	$/kW-yr	Variable/ Total
Variable Only	2.228	157.6	
Total	4.254	301.0	52.4%

Delivery Cost/Total Cost Ratio 62.8%

Time Periods			Delivery Services					Bi-Peak? FALSE	Price				Bill Total***	
Season	Period	Days and Times	Delivery Variable Charge (¢/kWh)	Delivery Variable Cost ($/kW-yr)	Delivery Demand Charge ($/kW-mo)	Delivery Demand Cost ($/kW-yr)	Delivery Monthly Charge* ($/kW-mo)	Delivery Monthly Cost * ($/kW-yr)	Variable Charges Only (¢/kWh)	Capacity, Grid, Demand, Charges Only ($/kW-year)	Capacity, Grid, Demand, Charges Only ($/kW-month)	Total Energy + Demand (¢/kWh)	(¢/kWh)	($/kW-yr)
Summer May - Sept	Peak	11:00 A.M. - 6:00 P.M Weekdays.	3.5565	25.0	11.09	55.5	0.00	0.0	9.06	55.5	11.09	16.55	16.95	119.1
Months (#) 5	Mid-Peak	6:00 A.M. - 11:00 A.M., 6:00 P.M. - 10:00 P.M. Weekdays	2.242	18.1	5.65	25.4	0.00	0.0	6.74	25.4	5.65	9.42	9.89	79.9
	Off-Peak	10:00 P.M. - 6:00 A.M. Weekdays, All Hours Weekends and Holidays	1.647	27.1	0.00	0.0	0.00	0.0	3.85	0.0	0.00	3.85	3.85	56.5
Winter Oct - Apr	Peak	5:00 P.M. - 8:00 P.M Weekdays.	3.034	12.2	4.58	28.9	0.00	.	5.53	28.9	4.58	11.99	12.7	51.1
Months (#) 7	Mid-Peak	6:00 A.M. - 5:00 P.M., 8:00 P.M. - 10:00 P.M Weekdays	2.251	37.1	5.65	33.6	0.00	0.0	4.25	33.6	5.65	5.99	6.29	103.6
	Off-Peak	10:00 P.M. - 6:00 A.M. Weekdays, All Hours Weekends and Holidays	1.663	38.1	0.00	0.0	0.00	0.0	3.36	0.0	0.00	3.36	3.36	68.7
		Annual	2.228	157.6	11.9	143.3	0.0	0.0	4.75	143.3	27.0	6.26	6.77	479.0

*** Equivalent values expressed in different units
Total Cost = supply cost + delivery cost

Energy Demand and Use

Table 24. PG&E Customer Seasonal and Time-of-Day Demand and Energy Use

Variable	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Totals
Customer Name	**Large Industrial/Institutional**												
													365
Season	W	W	W	W	**S**	**S**	**S**	**S**	**S**	W	W	W	
Facility Default	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	
Maximum Override													
Demand Value Used	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	Max =1000
Peak Demand Factor	**.90**	**.90**	**.90**	**.95**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**.95**	**.90**	**.90**	
													1,188
Load Factor in period, each month **(input)**	**.85**	**.85**	**.90**	**.90**	**.95**	**.95**	**.95**	**.95**	**.95**	**.90**	**.90**	**.85**	
Load Hours in period	54	54	58	58	141	141	141	141	141	58	58	54	1,097
Mid Peak Demand Factor	**.85**	**.85**	**.85**	**.85**	**.90**	**.90**	**.90**	**.90**	**.90**	**.85**	**.85**	**.85**	
													2,889
Load Factor in period, each month **(input)**	**.80**	**.80**	**.85**	**.85**	**.85**	**.85**	**.85**	**.85**	**.85**	**.85**	**.80**	**.80**	
Load Hours in period	222	222	235	235	162	162	162	162	162	235	222	222	2,400
Off Peak Demand Factor	**.85**	**.85**	**.85**	**.85**	**.90**	**.90**	**.90**	**.90**	**.90**	**.85**	**.85**	**.85**	
													4,683
Load Factor in period, each month **(input)**	**.70**	**.70**	**.75**	**.75**	**.80**	**.80**	**.80**	**.80**	**.80**	**.75**	**.70**	**.70**	
Load Hours in period	282	232	302	284	325	306	325	325	306	302	265	282	3,536
Total Load Hours (per inputs above)	558	508	595	577	627	608	627	627	608	595	545	558	7,032
Cumulative (Annual) Use Hours	558	1,066	1,661	2,238	2,865	3,473	4,100	4,727	5,335	5,930	6,474	7,032	
Monthly Load Factor	75.0%	75.6%	80.0%	80.2%	84.3%	84.4%	84.3%	84.3%	84.4%	80.0%	75.6%	75.0%	80.3%

Appendix C. Description of Distributed Generators

Leading distributed generation technologies used in this study were selected because they were considered to be cost-effective, more efficient, cleaner and dispatchable. Renewable technologies such as photovoltaics and wind were not included in the study, due to their non-dispatchability and zero emissions.

Internal Combustion Engine Generators

A reciprocating (piston-driven) internal combustion engine generator set (genset) includes an internal combustion engine as prime mover coupled with an electric generator. The engine is usually one of two types:

1) "spark-ignited" combustion of fuel – gasoline fueled automobile engines employ the Otto heat cycle
2) compression ignition of fuel (Diesel heat cycle) – fuel is combusted by compressing it, causing heat leading to ignition of fuel.

Diesel Fueled Diesel Engine Gensets

This type of power plant consists of a Diesel cycle engine prime mover, burning Diesel fuel, that is coupled to an electric generator. The Diesel engine operates at a high compression ratio and at relatively low rpm (compared to Otto cycle/spark engines and to combustion turbines).

Diesel fueled Diesel engine gensets are very common, worldwide, especially in areas where grid power is not available or is unreliable. They are manufactured in a wide range of sizes up to 15 MW; however, for typical distributed energy applications, multiple small units, rather than one large unit, are installed for added reliability.

These power plants can be cycled frequently and operate as peak load power plants or as load-following plants. In some cases, usually at sites not connected to a power grid, Diesel gensets are used for baseload operation (sometimes referred to as "village" power). Diesel gensets are proven, relatively simple, and extremely reliable, and should have a service life of 20 to 25 years if properly maintained.

Depending on duty cycle and engine design, O&M for Diesel gensets can vary widely, typically from two to five ¢/kWh. Frequent cycling increases O&M costs considerably. Typical Diesel genset heat rates (HHV) range widely from 9,500 Btu/kWh up to 13,000 Btu/kWh.

Nitrogen oxide (NO_x) emissions are usually the major concern with respect to siting and permitting of a Diesel engine plant though exhaust cleanup and combustion improvements that reduce emissions occur regularly. Particulate emissions must be addressed and SO_2 may be an issue if the sulfur content of the oil is high. Carbon monoxide (CO) emissions may also be an issue. If Diesel gensets are too noisy, sound attenuation enclosures may be needed.

Note again that Diesel engine gensets run on Diesel fuel. Increasingly, natural gas is used, especially where emissions and environmental permitting are issues. However, Diesel cycle engines cannot operate on natural gas alone because natural gas will not combust under pressure like Diesel fuel does, so they must operate in what is called "dual fuel" mode. Natural gas is mixed with a small portion of Diesel fuel so that the resulting fuel mixture (i.e., 5 – 10% Diesel fuel) *does* combust under pressure. This requires modest modifications to and de-rating of a Diesel cycle engine.

Natural Gas Fueled Internal Combustion Engine Gensets

A natural gas fueled genset includes a reciprocating (piston-driven) internal combustion engine as prime mover coupled with an electric generator. The engine prime mover is usually one of two types:

1) "spark-ignited" combustion of natural gas (Otto heat cycle), whose operation is very similar to gasoline fueled automobile engines, or
2) "dual-fueled," Diesel heat cycle engines modified to use *mostly* natural gas as described in the previous section

Although Diesel and spark-ignition engines used for transportation applications are common, natural gas fueled versions are not so ubiquitous. But because the underlying technology is commercial and well known, in theory natural gas fired versions (for power generation) could become much more common in sizes ranging from kilowatts to megawatts. (For distributed energy systems small multiple unit systems would probably be installed rather than one single large unit, to improve electric service reliability.)

Natural gas-fueled reciprocating engine gensets can be cycled frequently to provide peaking power or load-following or they can be used for baseload or cogeneration applications. They employ mostly well-proven technology and are very reliable. Service life should be at least 20 to 25 years if properly maintained.

O&M cost is similar to and possibly somewhat lower than that for Diesel gensets. It typically ranges from two to five ¢/kWh. Frequent cycling increases O&M costs considerably. Typical heat rates (HHV) also have a wide range, from 9,500 to 13,000 Btu/kWh.

Nitrogen oxide (NO_x) emissions are an important characteristic of many natural gas-fueled reciprocating engine gensets as are carbon monoxide (CO) emissions, although control technology is available and improving. Sound attenuation enclosures may be needed if natural gas fueled reciprocating engine gensets are too noisy.

Combustion Turbines

Combustion turbines (CTs) or gas turbines burn gaseous or liquid fuel to produce electricity in a relatively efficient, reliable, cost-effective, and in some instances clean manner. Generically, CTs are "expansion turbines" which derive their motive power from the expansion of hot gases through a turbine with many blades. The resulting high-speed rotary motion is converted to electricity via a connected generator. CTs use a Brayton heat cycle: A full CT generation system consists of a fuel-air compressor, a combustor, and the turbine itself, combined on one shaft with the generator and ancillary subsystems.

CTs are typically classified as either: industrial or frame types which were designed from the outset for electric power generation and other stationary applications; or aeroderivative types based on light and efficient jet aircraft engine designs.

CT generation systems are commonplace as electricity generators and are available in sizes from hundreds of kilowatts to very large units rated at hundreds of megawatts. CT systems have a moderate capital cost, but they often are used to burn relatively high cost distillate oil or natural gas. CT generation systems should have a minimum service life of 25 - 30 years if properly maintained and depending on how and how often they are used.

Depending on the manufacturer, size and the model of CT, full-load heat rates (HHV) for commercial equipment can range from 8,000 Btu/kWh to 14,000 Btu/kWh. O&M costs are relatively low, due to their simplicity, reliability, standardization of parts and maintenance protocols, and a robust support industry.

CTs can start and stop quickly and can respond to load changes rapidly making them ideal for peaking and load-following applications. In many industrial cogeneration applications they would also make excellent sources of baseload power, especially at sizes in the 5 to 50 MW range.

From an environmental and permitting standpoint, nitrogen oxide (NO_x) emissions from CTs are the primary issue.

Microturbine Generators

Microturbines are small versions of traditional gas turbines, with very similar operational characteristics. They are based on designs developed primarily for transportation related applications such as turbochargers and power generation in aircraft. In general, electric generators using microturbines as the prime mover are designed to be very reliable with simple designs, some with only one moving part. Typical sizes are 20 to 300 kW.

Microturbines are "near-commercial" with many demonstration and evaluation units in the field. Several companies, some of which are very large, are committed to making these devices a viable, competitive generation option. One key characteristic of microturbines is that their simple design lends itself to mass production, should significant demand materialize. Of course, until demand *does* materialize so that manufacturing can scale up economically, microturbines will remain as a “near” commercial option that cannot compete on an economic basis.

On the downside, fuel efficiency is somewhat or even much lower than that of larger combustion turbines and internal combustion reciprocating engines, and emissions are comparable to somewhat lower. Note, however, that if microturbines are used in situations involving use of steam and/or hot water, microturbines can generate electricity and thermal energy (combined heat and power, CHP) cost-effectively. Definitive data on reliability, durability, and O&M costs are just being developed.

Advanced Turbine System (ATS) Generators

ATS was developed as a small, efficient, clean, low-cost, power generation prime mover by Solar Turbines in conjunction with the U.S. Department of Energy. It employs the latest combustion turbine design philosophy and state-of-the-art materials. It generates 4.2 MW. Fuel requirements are about 8,800 – 9,000 Btu/kWh (LHV). Installed cost is expected to be about $400/kW with O&M expected to be below 5 mills per kWh. With advanced emission controls NO_x can be well below 10 ppm, though the effect on efficiency is not trivial and the effect on installed cost can be significant.

Fuel Cells

Fuel cells are energy conversion devices which thermochemically convert hydrogen (H_2) or high-quality (hydrogen-rich) fuels like methane into electric current very efficiently and with minimal environmental impact.

Fuel cells are very modular (from a few watts to one MW) and are usually categorized by the type of electrolyte used. The most common electrolyte is phosphoric acid. A few carbonate demonstration fuel cells have been built, and solid oxide is under development. Polymer electrolytic membrane fuel cells are also under development for transportation and distributed power applications.

A fuel cell system consists of a fuel processor, the chemical conversion section (the fuel cell "stack"), and a power conditioning unit (PCU) to convert the direct current (DC) electricity from the fuel cell's stack into alternating current (AC) power for the grid or for loads and for supporting hardware such as gas purification systems. Unless hydrogen is used as the fuel, prior to entering the fuel cell stack, the raw fuel [e.g., natural gas] must be dissociated into hydrogen and a supply of oxygen from air must be available. Within the fuel cell stack, the hydrogen and oxygen react to produce a voltage across the electrodes, essentially the inverse of the process which occurs in a water electrolyzer. This DC power is converted to AC power by the PCU.

Fuel cells are not common, although hundreds are in service worldwide and the number of units in service is growing rapidly. Advocates are awaiting expected manufacturing advances that will reduce fuel cells' equipment cost and improve its efficiency such that they produce very low cost energy. Typical plant unit sizes (which can be aggregated into any plant output rating needed) are expected to range widely from a few kW to 200 kW.

O&M cost for fuel cells is expected to be similar to that for baseload combustion technologies in the near term, ranging from about one to two ¢/kWh; but O&M costs are expected to be much lower in the future as plant designs mature and as important component materials are perfected.

Current fuel cells based on phosphoric-acid electrolytes have heat rates (HHV) of 9,400 Btu and cost in excess of $2000/kW installed. Advanced fuel cell systems utilizing the emerging proton exchange membrane (PEM) technology are expected to have efficiencies in the 60 to 65 percent range over the next 5 years and ultimately to cost less than $1000/kW installed.

Fuel used by fuel cells is not combusted and because fuel conversion to electricity is relatively efficient, fuel cells' emissions of key air pollutants are much lower than for combustion technologies. This is especially true for NO_x, the major pollution-related concern affecting viability of all reciprocating engine and combustion turbine based options. Carbon monoxide, sulfur dioxide and volatile organic compound (VOC) emissions from fuel cells are also negligible or non-existent.

Appendix D. Combined Heat and Power (CHP) and Boiler Emissions – Assumptions and Calculations

Introduction

This appendix discusses the emissions implications of combined heat and power (CHP) applications for distributed generation. The data used herein reflect the latest information as of 7/1/2000.

Boilers

In the CHP scenario, a distributed generator is used to generate electricity, and a waste heat recovery system is used to provide the process heat for the load application, thereby eliminating the boiler. As a result, air emissions from the boiler are avoided. The avoided boiler was assumed to be natural gas fired and 85% fuel efficient.

Avoided boiler air emissions were calculated based on emission factors from the US EPA report AP-42, Section 1.4: Natural Gas Combustion [11]. This document provides emissions in lbs. per standard cubic foot (SCF) of natural gas fuel input to the boiler.

Of greatest interest are NO_x emissions. The EPA reports a wide range of emission factors for NO_x. This variation is driven by criteria including boiler age, “air quality jurisdiction” within which boilers are located (if any), boiler fuel efficiency, type of combustor, and emission control equipment installed.

Newer boilers located in regions with strict air emission regulations have reported emissions of about 35 – 50 pounds per SCF of fuel input. Older boilers, especially larger ones have reported NO_x emissions of about 290 lb/SCF of gas.

It is assumed that boilers replaced by DG/CHP systems would not be recently purchased equipment, and therefore not the most environmentally benign. Therefore, the avoided NO_x emissions from the boiler are:

Nationwide: 150 lb/SCF of fuel input to the boiler

California: 100 lb/SCF of fuel input into the boiler.

Of course, any specific project will be different; these values are assumed to be the average or typical values for boilers that are likely to be replaced with DG/CHP.

Often these values are better utilized if expressed in units of pounds per MMBtu of fuel input. Per EPA AP-42, there are 1,020 Btu per SCF. To convert the above values given in units of lb/SCF to units of lb/MMBtu, divide them by 1,020. For example, for boiler NO_x emissions of 100 lb/SCF of fuel into the boiler:

$$NO_x = 100 \text{ lb/SCF} \div 1{,}020 = 0.09804 \text{ lb/MMBtu}_{in}$$

Generation

As discussed elsewhere in this report, two generators were considered for CHP operation: the Advanced Turbine System (ATS) and the microturbine. The waste heat recovery factor is the portion of waste heat from generation that is recovered during generation operation. It accounts for losses associated with gathering and transporting heat. For combustion turbines, exhaust temperatures are typically several hundred degrees F (e.g., 670 ^{o}F for the ATS). For both technologies a waste heat recovery factor of 0.7 is assumed. These data were obtained from Solar Turbines Corp. [4].

To calculate heat recovery, first calculate the waste heat from generation by subtracting the heat energy (Btu) in a kWh of electricity (Btu/kWh) from the generator's heat rate (also in Btu/kWh):

> 9,500 Btu/kWh – 3,413 Btu/kWh = 6,087 Btu/kWh of waste heat, for each kWh generated

Next, apply the waste heat recovery factor, 0.7 in this case, to determine the actual heat recovered:

> 6,087 Btu/kWh * 0.7 = 4,261 Btu/kWh

That is the actual heat delivered to the heat load. But the boiler that would have provided that heat is only 85% fuel-efficient. That means that to get that same 4,261 Btu/kWh delivered from the CHP plant, the boiler would burn:

> 4,261 Btu/kWh ÷ 85% = 5,013 "effective" Btu/kWh from the CHP generator.

Avoided boiler emissions associated with each kWh of electricity generated by the CHP operation are calculated based on that heat recovery. As described above, boiler emissions are expressed in units of pounds emitted per MMBtu of fuel input. That emission factor is multiplied by the number of millions of heat Btu per kWh recovered during CHP operation. The result is the pounds of avoided boiler emissions per kWh of electricity from the CHP plant.

First, convert heat recovered per kWh to units of MMBtu/kWh:

> 5,013 Btu/kWh ÷ 1,000,000 Btu/MMBtu = 0.005013 MMBtu/kWh

The boiler emission factor in units of lb/MMBtu of fuel input to the boiler (described above) is multiplied by that amount of avoided boiler fuel use.

For boiler NO_x emissions of 100 lb/SCF of fuel into boiler:

> (0.09804 lb NO_x/MMBtu boiler fuel in)*(0.005013 MMBtu/kWh)
> = .000491 lb

of boiler NO_x emissions avoided per kWh of electricity from a CHP generator.

Calculating Change in Emissions Due to CHP Operation

First, emissions associated with only the generation plant (i.e., without regard to CHP) are calculated. During hours when the distributed generator operates its emission factors apply. During hours when the distributed generator does *not* operate, the central generation emission factors apply. That yields the total amount of emissions associated with electricity from distributed generation plus electricity provided by the grid.

Next, emissions associated with the distributed generator are compared to the avoided emissions, i.e., emissions that do not occur because the distributed generator is used. To do that, emissions are first calculated as if the grid supplied *all* electricity, using the central generation emission factors. That amount is then added to the boiler emissions that would have occurred if the CHP did not provide heat needed for the facility. It is assumed that the boiler would have operated during the same hours that the DG/CHP operates.

The calculation for the percent change is as follows:

$$100 * \left[\frac{EF_{DG} * P_{DG} + EF_G * (1 - P_{DG})}{EF_G + EF_B * P_{DG}} - 1 \right],$$

where: EF_{DG} = DG-only emissions factor, lb/kWh
EF_G = central generation emissions factor, lb/kWh
EF_B = boiler emissions factor, lb/kWh
P_{DG} = fraction of electricity supplied by DG/CHP system

A few details are worth noting:

- An underlying assumption for this study is that if a distributed generator with CHP is installed, the boiler whose heat is being supplied by waste heat from the distributed generator must be removed and cannot be replaced, in accordance with existing air emissions regulations. For this to be feasible, the generator must be approximately as reliable a heat source as the boiler was. In addition, if the generator is to serve as a "replacement" for the boiler as a facility's heat source, it may have to be operated when incremental operation cost exceeds the time value of electricity plus avoided boiler fuel cost. In this case, the project's overall financial benefits may be reduced.

- Boiler emissions factors are expressed in units of lb/kWh of generation from the distributed generator. Those emission-specific factors are a function of: a) distributed generator fuel efficiency, b) distributed generator waste heat recovery factor, c) boiler fuel efficiency, and d) pounds of emissions from boiler per MMBtu of fuel input, per US EPA AP-42.

Appendix E. Compendium of Reviewers' Comments

The following is a summary of the substantive comments received from the reviewers of the report, followed by a description of the actions taken by the authors in response to the comments, and indexed to the current page numbering. Editorial comments (typographical errors, spelling, etc.) are not included.

<u>California Air Resources Board (CARB)</u>

1) Executive Summary, Key Conclusion #3: It seems that the first sentence in the first paragraph could be rephrased to say the same thing in a more direct manner. Maybe just drop the opening phrase.
[This paragraph was reworded for clarity.]

2) Section 3, CHP equation (before Table 1): Is this equation correct? I'm not sure about the first term.
[The equation is correct. The last term was revised for clarity and consistency.]

3) Section 5: In Figure 3, where is the explanation of the avoided cost frequency curve?
[See section titled *Variability of Utility Avoided Cost*, p. 20.]

4) Executive Summary, Key Conclusions (and other places in the report): For the first bullet under "Observations," words like "minimal" and "modest" are used to describe the amounts of emissions from DGs. I would suggest that numbers in tons or percent be used to quantify the emissions.
[This statement was reworded to be more quantitative.]

5) Appendix A, Reliability: What is the origin of the rate for "unserved" electricity?
[See Reference [21], the paper by Woo and Pupp on value of service.]

6) Towards the end of the report, the following or a similar statement is made a few times: "If DGs are compared to the most likely type of new central power plant that would be added to meet new load, DGs have a much less significant incremental effect on total air emissions." This statement doesn't sound right. New central station power plants should be much cleaner than the emissions from state-of-the-art DG technology with the exception of fuel cells.
[The Authors added language in several places in the report to clarify this point.]

7) Appendix C: Contractor might want to give an overview of the ATS program. It is understood that Solar's unit was used in the analysis, but there are three other manufacturers involved producing three other gas turbines of varying outputs and configurations.
[Further discussion of the ATS program is beyond the scope of the report. The authors used turbine data, albeit from only one manufacturer, with the concurrence of the Advisory Board for the project.]

8) Recommend adding tables for the incremental emissions attributable to DG in tons per year and also as a percentage of the incremental emissions from the central station scenario.
[This is beyond the scope of the report.]

9) The report states that peak load DG will not have a significant emissions impact. These statements may be misunderstood. It is outside of the scope of the report to look at temporal effects of emissions; however, peak power emissions often occur on or near peak ozone days. All of the emissions attributable to peak power production would occur in a short timeframe. Ozone standards are based on 1 hour and 8 hour averages; any increase in emission in that timeframe may cause significant impact on air quality.

Therefore, a statement that juxtaposes peak power, which may occur over a number of days, with emissions impacts, which are averaged over the entire year, is likely to be misunderstood. It is likely that some may confuse "no significant emissions impact" with "no significant air quality impact". In fact, the report on page 12 concludes that peaking DG "would add minimal to modest amounts of air pollution overall." There is insufficient evidence to draw this conclusion. For example, if a site's annual ozone violations were to increase from 2 days to 4 days, that would constitute a significant increase in air pollution even though the annual emissions increases which may have caused the violations were "minimal to modest". These statements should be deleted.
[These statements were re-worded with the above comments in mind.]

10) The sentence, "If DGs are compared to the most likely type of <u>new</u> central power plant that would be added to meet new load, DGs have a much less significant incremental effect on air emissions." conflicts with slides 12 and 13 of the presentation. The latest CEC information suggests that the cumulative mix of new CT and in-state is cleaner than in-state existing. Therefore, the sentence should read "If DGs are compared to the most likely type of <u>new</u> central power plant that would be added to meet new load, DGs have a <u>more</u> significant incremental effect on air emissions."
[The Authors incorporated the above comments into this part of the report.]

<u>California Energy Commission (CEC)</u>

1) The overall format of the report and flow of information should be more streamlined to make reading easier to follow.
[Numerous editorial corrections were made with this in mind.]

2) The investor-owned "utility" in California has been separated into three distinct companies who may not mix costs or benefits. Generation, transmission and distribution are separate with separate revenue streams and motivations. Thus, an avoided cost analysis should not include a benefit to a utility of generation and transmission or transmission and distribution, much less generation plus transmission plus distribution. A UDC would be motivated to reduce only distribution costs. Currently, a transmission

owner cannot invest in distributed generation and recover the costs in the wires charge. Thus, reducing transmission costs should not be included in the equation. This is a FERC policy, subject to change in the future.

Based on the above comments, the consequence would probably reduce the estimates of likely UDC penetration. The estimates might be more appropriate for municipal utilities, which are still vertically integrated.

[The Authors' goal was to estimate the market potential of distributed generation; of necessity such an analysis should include all possible benefits accruing to installation of DG. While it may be problematical to achieve recognition for all the benefits or to allocate them to stakeholders in the associated planning processes, we feel they must be included in the analysis.]

3) References to the clean generation are confusing. It is believed that old natural gas boilers dominate the California generation system. However, the electricity used in state is largely from out-of-state, hydro, nuclear, and cogeneration. The existing natural gas-fired boiler system is used for summer peaks and load following.   "Generation" is the process or system and not the product or electricity. Please review the Report to clarify whether the reference is to the system or the electricity.
[See response to CARB item 10), above.]

4) While this report focuses on the California environment, comparison of this study with results obtained in the national study would be very informative and will provide a better understanding of how the California impacts are different from the national study results.
[This task would be beyond the scope of the study.]

5) Appendix C: The attachment describing the technologies (at the end of the report) should also include a brief statement mentioning that only hydrocarbon-fired generation is being considered and that there are other technologies (solar, wind, other renewable) which would gain some market share in the eventual penetration of DG. This will not leave the readers wondering why the other technologies are not considered. (The main report actually addresses this very briefly. However, duplication of this information in the attachment will keep the issues clear for all readers.)
[The Authors added an explanatory paragraph at beginning of Appendix C.]

6) Executive Summary, Key Conclusions and Section 5, Observations: The statements regarding peakers may be misleading. The "per unit of energy" comparisons are valid and important. However, just because peaker emissions are small on an annual basis, peaker air emissions on a daily basis can be high in comparison to other existing peaker air emissions or daily emissions inventories. Until the report provides the system peaker average emissions for direct comparison, the system average emissions are a reasonable proxy. Just do not say that the effects are insignificant.
[The Authors edited these passages with the above comments in mind.]

7) Tables 6 and 7: Please verify the CO_2 values in Tables 6 and 7. They should be

consistent with each other and reflect/identify the three orders of magnitude difference compared to the other values in the tables.
[The CO_2 and CO values in Table 7 were corrected and are now consistent with those in Table 6.]

8) Tables 6 and 7: The discussion for Table 6 (and possibly Table 7) should reflect that the emission factors are frozen despite the continuing implementation of the boiler retrofit rules (i.e., BARCT) and new additions to the mix. The discussion may also need to mention the potential for the premature retirements of nuclear plants and the unknown effects of the pending sale of the PG&E hydroelectric system.
[Language was added to the report to clarify this discussion.]

9) Executive Summary: Re: 'Cost-effective DGs Compared to the "Next" Central Generation Plant' – Need to describe/explain the rationale for the statement in this paragraph.
[The Authors added clarifying language to this paragraph.]

10) Clarify the definition of "marginal" plant. One understanding is that marginal plants are those plants that are least competitive, generally operating on the "shoulder" or "peak". New generation may not fit this definition, as they will be very efficient, and pushed to the base rather than to the peak or shoulder. Perhaps these should be "incremental" plants. DER or new central could compete for this, as could existing marginal (i.e., old, inefficient, weak locational value) plants.
[Language discussing this subject has been revised to eliminate references to "marginal" plants, and instead refer to the "next" generating plants that would be built.]

11) Section 2: 'Distributed Resources Evaluated': Although photovoltaics are not dispatchable, they are still well suited for peaking duty since their peak performance occurs during utility peak load. Should this be discussed further in the Report? How is PG&E's PV at Kerman Substation working out?
[A further discussion of PV is beyond the scope of the report.]

12) What year dollars are used throughout the report? Are they indexed for inflation through the years? Need to clarify this issue if constant / nominal are used in different sections.
[All costs are in 1999 constant dollars. See language in Section 3, Note #2.]

13) Section 2, 'Distributed Resources Evaluated': Technically, hydroelectric is a renewable resource, along with biomass, geothermal, and wind. In the report, is it separated from the renewables category and included with the other conventional generation sources of nuclear and gas-fired?
[As stated, hydroelectric is included in the in-state central generation mix, not in the renewables category.]

14) Regarding the "significant deployment" of Diesel or dual fueled engines being problematic due to air emissions: Depending on the size of the DG units, it is possible to

pursue exemptions from permits or permits that are exempt from BACT or offsets. This may not be a problem for the DG owners, but could be a problem for regulators.
[As stated in the report, deployment of Diesels could be problematical: they are inexpensive, but relatively “dirty.”]

16) Depreciation [of customer-owned DGs] over five years sounds low. Is there a rationale for this assumption?
[See explanatory language in Section 6, “Customer Financials.”]

<u>Southern California Edison (SCE)</u>

1) The basic results of the study may show a higher potential market penetration than the real market will experience due to unrealistically low installed cost assumptions. The assumptions used would necessitate approximately a 70% reduction in the installed costs of microturbines over the next few years. This cost reduction in the short term is probably unlikely.

The installed costs used for IC engines are also assumed to be significantly below current levels (30%-40% less) and, because IC engines are a mature commercial product, it is even more unlikely that these cost reductions will occur.

Our data, gathered through direct experience as well as reports from DG conferences and other research entities suggests that the installed costs shown in the tables may not be realistic. This may be due to excluding some components such as gas compressors, for the microturbines or the use of projected costs from other sources. In either case more study of this most critical factor should occur before these costs are taken as fact. The total capital cost of the technology is most sensitive in determining the commercial status and thus the market penetration of the technology. Fuel cells are a prime example of this.
[The installed cost data was supplied by the manufacturers. See caveat at p. 10, ¶3, bullet #3.]

2) Tables 2 – 5: The emissions data shown for microturbines appears to be from one product line (Capstone) and seems to be correct for that line. Other major suppliers have microturbine product lines that may produce emissions in the range of 25 - 50 ppm and should be included in the mix. Use of industry average values in lieu of a specific manufacturers data would increase the emissions assigned to distributed generation for each air basin.
[See Section 3, second paragraph: data for microturbines was a composite of Allied Signal and Capstone data. At this point it is not possible to perform additional analyses with data from additional microturbines.]

3) [Ibid.] The heat rates shown for microturbines are also optimistic. Microturbines have current heat rates of approximately 15,500 Btu/kWh (HHV). They would need a 20 percent improvement in efficiency in the next two years to attain the target used in the study.

[The Authors agree; it was assumed that microturbines would improve or they would not exist in the market.]

California Council For Environmental And Economic Balance (CCEEB)

1) Preparation of this preliminary analysis of the air quality impacts from potential distributed generation sources has involved a lot of work dealing with numerous variables. Distributed Utility Associates has done a good job with limited resources on a complex task.

2) Executive Summary and Report Summary: The discussions at Committee meetings have given the Committee Members the necessary foundation to understand the assumptions and caveats that are an important foundation for the draft report. However, many policymakers may review only the Report Summary or the yet to-be-added Executive Summary. CCEEB suggests that Distributed Utility Associates add to the Report Summary and to the Executive Summary a set of key assumptions and caveats. As an example, the summary or list of assumptions and caveats should note that the report does not factor in utility standby charges that could significantly affect market penetration. As another example, the emissions considered for some existing power plants will decrease under district retrofit rules that have been adopted but have future compliance dates.
[Re standby fees, see language Executive Summary, Key Study Assumptions, bullet #7. See also previous comments/responses re: discussion of emissions.]

3) Often in policy debates, key charts or graphs are often discussed outside the context of the source document. Where key assumptions or caveats affect the information presented in tables, graphs or figures in the draft, Distributed Utility Associates should add a notation regarding the assumption(s) and/or caveat(s) on or by the table, graph or figure or as a footnote thereto.
[The Authors endeavored to include such information where possible.]

Caterpillar, Inc.

1) Tables 2 – 5: The Report does not speak to the emissions production associated with the entire fuel cycle. (For fuel cells this would be for the production of hydrogen.) While there are reasons for segmenting the treatment of emissions production from the source to the generation of power, we would recommend that the fuel cycle-total emissions concept be stated in the report.
[Tables 2 – 5 were corrected to show the amounts of NO_x produced in the hydrogen reforming process for fuel cells.]

2) Our second concern is that the Report Summary needs to reflect the balance regarding emission impacts that is contained later in the Report. For example, the Report states that the comparison of DG is to the existing mix of in-state generation which is "dominated by facilities with limited or no air emissions -- mostly nuclear and hydroelectric.” The

comparison of DG to hydro and nuclear, which makes up small percentage of the approximate 50,000 MWs of installed capacity, uses a methodology that employs a "static snapshot" of the existing system. The Report authors recognize the dynamic nature of California's generation mix as the Report later states that "changes in air emissions associated with cost-effective DG use in this study were based on a mix of central generation that is not sustainable." Further, the report states that "this study would be different if DGs were compared to the next source of capacity …the most likely type of <u>new</u> central power plant that would be added to meet new load."
[These concerns have been addressed in previous comments/responses.]

3) Section 1: Re The Distributed Utility Concept Overview: you treat the difference between supplying capacity and energy [elsewhere] in the text (e.g., Chapter 6). In the first paragraph noted, you refer to energy only. The distinction you are drawing is not explicit and may be inaccurate. A clarification is requested.
[This paragraph was revised for clarification.]

4) Was the cost of obtaining an air permit, along with emission offsets, considered and incorporated into the economic analysis?
[No. These costs would be variable and highly case-specific. This is now noted in the text.]

5) There is a reference to "recommendations for policy options" [in the Report Summary]. Will this be part of the report?
[No, this was outside the scope of the report. This phrase has been deleted.]

6) The comparison is made of "customer-owned DG producing 3 times higher per kW of cost-effective DG than utility DG." It is not clear how this result was determined. Its derivation is perhaps in the accompanying text of later chapters, but for those that read only the Report Summary, more explanation is required.
[This statement has been reworded to make the argument clearer: It follows from the foregoing paragraphs wherein it was stated that a utility only needs to operate a peaking DG for 200 hours a year to cost-effectively meet utility peak loads. Since a customer would need to operate about 600 hours per year to be cost-effective for his own load, it follows that customer-owned peaking DG will operate approximately 3 times longer, on a yearly basis, than a utility peaking DG; hence the emissions are 3 times higher as well.]

8) Reference is made to the "marginal" plant. Recommend that further elaboration is made in order to enable the Report Summary-Only-Reader to understand it.
[See response to CEC item 10) above.]

9) Diesel engines play a critical role in the provision of electrical services. They are used in emergency situations to provide reliable power *when the power grid or natural gas curtailments or gas interruptions* occur. In peak demand situations, prior to Stage 3 outages, these generators can be used to avoid or reduce the dependence on the existing fleet of emergency diesel generators. California's recent experience with a Stage 3

"black out" points out the need for thoughtful and measured consideration of clean diesel generators by California's policy makers.

10) CARB has played a pivotal role on many issues affecting power generation and air quality. In SB 1298 (Senators Bowen and Peace), presently before the Governor for signature, the concept of precertification of DG is advanced. *For smaller units, the* CARB *will adopt a certification program that has statewide applicability. For larger units, the* CARB *will issue guidance to the air districts that they in turn can use to develop appropriate rules*.

Appendix F. Reference Data for Distributed Generator Emissions

The California Air Resources Board and Caterpillar, Inc. supplied the following source data for emissions from engines and gas turbines. These data were to used as a reference in order to determine the most appropriate emissions factors for the years 2002 and 2010, given the applications (peaking and baseload, utility and customer), sizes of distributed generators, and the anticipated air regulations.

Comparison of emission factors was performed using emissions test data and regulations both promulgated and proposed. For the internal combustion engines, it should be noted that some of the emission standards used in the comparison are for future years, such as the lower NO_x limit for Diesel engines. Consequently, these emission factors may not be attainable presently. In addition, some of the numbers may apply to engines used in on-road, vehicular applications which have a more transient nature than a stationary application such as a genset. Other numbers are non-road certified emissions factors which are averaged over multiple steady-state operating modes rather than representing a single operating point. Also, the emission factors cover a wide range of power ratings.

DIESEL ENGINE EMISSION FACTORS, 2002/2010 (g/bhp-hr)

POLLUTANTS ➔	**NO_x**	**SO_x**	**CO**	**CO_2**	**VOC**	**PM**
DUA (670 HP)	5.1	0.10	10.15	257.1	0.68	0.88
CARB	2.7 - 14.0	0.18 - 0.93	0.4 - 4.3	500 - 594	0.1 - 1.5	0.04 - 1.0

Note: Assume CARB Diesel (0.05% sulfur cap)

References: AP-42, U. S. EPA Emission Factors
Certified Emission Factors for MY 99 Nonroad Engines
Certified Emission Factors for MY 99 Onroad Engines
CARB BACT Determination
BAAQMD BACT Determination
Emission Standards for Nonroad Diesel Engines – U. S. EPA

SPARK-IGNITED ENGINE EMISSION FACTORS, 2002/2010 (g/bhp-hr)

POLLUTANTS ➔	**NO_x**	**SO_x**	**CO**	**CO_2**	**VOC**	**PM**
DUA (335, 670 HP)	0.86 - 1.10	0.0034	2.0 - 2.7	243.5 - 328.1	0.3 - 0.6	0.29 - 0.6
CARB	0.068 - 11.8	-	0.6 - 37.0	260.4 - 655	0.01 - 11.0	0.01 - 0.23

References: AP-42, U. S. EPA Emission Factors
Certified Emission Factors for Moyer Program Engines
Certified Emission Factors for MY 99 Onroad Engines
CARB BACT Determination
BAAQMD BACT Determination
Large Spark-Ignition Offroad Engine Rulemaking – CARB

DUAL FUEL ENGINE EMISSION FACTORS, 2002/2010 (g/bhp-hr)

POLLUTANTS ➔	**NO_x**	**SO_x**	**CO**	**CO_2**	**VOC**	**PM**
DUA (600 - 670 HP)	1.9 - 3.38	0.02 - 0.034	10.1 - 11.2	288 - 311	0.17 - 0.41	0.26 - 0.36
CARB	2.4 - 8.2	0.016	3.4 - 13.5	350	0.2 - 0.8	0.12 - 0.21

References: AP-42, U. S. EPA Emission Factors
The ECI Dual Fuel Sourcebook (1993)
OceanAir Environmental (10/24/96)
Diesel & Gas Turbine Worldwide (October 1996)

GAS TURBINE EMISSION FACTORS, 2002/2010 (g/bhp-hr unless otherwise noted)

POLLUTANTS ➔	**NO_x**	**SO_x**	**CO**	**CO_2**	**VOC**	**PM**
DUA - MICROTURBINE (45 MW)	0.34 - 0.42	0.01 - 0.088	0.59 - 0.90	372 - 423	0.014 - 0.02	0.027 - 0.03
DUA - ATS (4.2 MW)	0.21 - 0.37	0.007	0.88	321	0.01	0.024
DUA - CONV. CT (3.5 MW)	0.38 - 0.42	0.007 - 0.01	0.45 - 0.51	355 - 406	0.014	0.027 - 0.03
CARB	1.3 - 1.6	0.0054	0.39 - 0.83	397 - 399	0.01 - 0.09	0.15
BACT*	2 - 20 ppm	Note	5 - 10 ppm	–	2 - 10 ppm	Note

Note: CARB BACT Powerplant Guidance specifies SO_x and PM emission limits corresponding to combustion of NG with sulfur content of no more than one grain per one hundred standard cubic feet.

* BACT limits are specified in terms of concentration (ppmv) of the pollutants in the exhaust adjusted to 15% oxygen.

References: AP-42, U. S. EPA Emission Factors
BACT Powerplant Guidance Document – CARB
CARB BACT Determination
BAAQMD BACT Determination
SCAQMD BACT Determination

Caterpillar supplied the following data for the 670 hp (500 kW) engines, as a particular point of reference:

Diesel Engine		500 ekw
Application		Peakload
Aftercooler Water Temp		30 Deg. C
NO_x	lb/kw-hr	0.017
SO_x	lb/kw-hr	0.009
CO	lb/kw-hr	0.006
CO_2	lb/kw-hr	1.92
VOC	lb/kw-hr	0.005
PM	lb/kw-hr	0.007
UHC	lb/kw-hr	0.006

Gas Engine		500 ekw
Application		Peakload / Baseload
Aftercooler Water Temp		32 Deg. C
NO_x	lb/kw-hr	0.006
SO_x	lb/kw-hr	0.003
CO	lb/kw-hr	0.009
CO_2	lb/kw-hr	1
VOC	lb/kw-hr	0.0015
PM	lb/kw-hr	0.0004
UHC	lb/kw-hr	0.01